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Alliance Research Center

ENGINEERING DEVELOPMENT OF ADVANCED COAL-FIRED LOW-EMISSIONS BOILER SYSTEM

PHASE II SUBSYSTEM TEST DESIGN AND PLAN
An addendum to the Phase II RD&T Plan
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FINAL EDITION

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A. Background

Shortly after the year 2000 it is expected that new generating plants will be needed to meet the growing demand for electricity and to replace the aging plants that are nearing the end of their useful service life. The plants of the future will need to be extremely clean, highly efficient and economical. Continuing concerns over acid rain, air toxics, global climate changes, ozone depletion and solid waste disposal are expected to further tighten regulations.

In the late 1980's it was commonly believed that coal-fired power plants of the future would incorporate either some form of Integrated Gasification Combined Cycle (IGCC) or first generation Pressurized Fluidized Bed Combustion (PFBS) technologies. However, recent advances in emission control techniques at reduced costs and auxiliary power requirements coupled with significant improvements in steam turbine and cycle design have clearly indicated that pulverized coal technology can continue to be competitive in both cost and performance.

In recognition of the competitive potential for advanced pulverized coal-fired systems with other emerging advanced coal-fired technologies, DOE's Pittsburgh Energy Technology Center (PETC) began a research and development initiative in late 1990 named, Combustion 2000, with the intention of preserving and expanding coal as a principal fuel in the generation of electrical power. The project was designed for two stages of commercialization, the nearer-term Low Emission Boiler System (LEBS) program, and for the future, the High Performance Power System (HIPPS) program. B&W is participating in the LEBS program.

Major goals of the DOE-PETC LEBS Program include:

•	NO_x	0.20 lb NO_x/MBtu
•	SO_2	0.20 lb SO_2/MBtu
•	Particulates	0.015 lb particulate/MBtu
•	Air Toxics	In compliance with potential regulations
•	Solid By-product	Minimization with utilization or regeneration preferred
•	Plant Efficiency	≥38%
•	Cost-of-electricity	At or below that of a current NSPS plant
•	Commercialization	2000

Since the state-of-the-art has progressed significantly during the course of the program, B&W's LEBS project goals have been continually refined throughout the project to maintain relevance with current commercial capability. The B&W LEBS project goals are as follows:

•	NO_x	0.10 lb NO_x/MBtu
•	SO_2	0.10 lb SO_2/MBtu
•	Particulates	0.005 lb particulate/MBtu
•	Air Toxics	In compliance with potential regulations
•	Solid By-product	Minimization with utilization or regeneration preferred
•	Plant Efficiency	≥42%
•	Cost-of-electricity	At or below that of a current NSPS plant
•	Commercialization	2000

The LEBS program consists of four phases over 7 years. Phase I consisted of a thorough review and assessment of potential advanced technologies and techniques for the control of emissions, and a review of boiler design options. The information developed during these assessments was used in finalizing subsystem process selection for a B&W LEBS power plant.

A preliminary commercial engineering design and a design uncertainties analysis were then completed to identify areas of uncertainty in the selected LEBS concept. Based on the areas of uncertainty identified, a research, development, and test (RD&T) plan was created to eliminate and/or reduce the deficiencies. Some small-scale development work was completed in Phase I.

In Phase II, small-scale development work continued to further define the systems within the B&W LEBS. In order to develop the design base for and to ensure successful operation of the Proof-of-Concept Test Facility in Phase IV, testing of the NO_x, SO_x, and control subsystems in a large-scale pilot facility is necessary. Subsystem testing will occur in B&W's state-of-the-art Clean Environment Development Facility rated at 100 MBtu/hr (29.3 MW_t) as Task 11 of Phase II. A schedule is provided in the conclusion section of this report.

This document is intended to define the subsystem test plans and associated facility designs for the NO_x, SO_x, and control subsystem test series. **This document supersedes the subsystem testing information provided in the Phase II Research, Development, and Test Plan (RD&T) -- it is therefore, provided as an addendum to the RD&T Plan.** The test plan and test facility design documented in this report were completed under Task 9 (Subsystem Test Design and Plan), Phase II of the B&W LEBS project.

B. B&W LEBS Configuration

The B&W low emission boiler system (LEBS) is pictured in Figure 1. It consists of five subsystems; 1) Boiler development, 2) NO_x control, 3) SO_2/Particulate/Air Toxics control, 4) Controls & Sensors development, and 5) Balance-of-plant (BOP) development. The work developed by the Controls & Sensors Subsystem is completely embodied within the other four subsystems.

The boiler is a pulverized-coal fired, hopper bottom boiler using advanced steam conditions, with a typical boiler island equipment scope-of-supply. Advanced design B&W MPS pulverizers with rotating classifiers will prepare the coal to obtain optimum combustion performance using advanced low-NO_x burners, located on the lower furnace front and rear walls.

The furnace is a straight wall, wall-fired design that incorporates advanced staging in order to meet the NO_x emission goal. The furnace is divided into two zones, a lower primary combustion zone and an upper furnace, or burnout zone. Advanced low-NO_x burners are located on both the front and rear walls of the primary zone. Advanced overfire air (OFA) ports are located on both the front and rear walls of the furnace, at the interface between the primary and upper furnace zones. The furnace includes spiral tube circuitry up to about the upper furnace arch nose, where a steam mix occurs, and the tubes then continue upward in a vertical manner.

The upper furnace and boiler convection pass configuration incorporates modifications to effectively integrate furnace limestone injection and advanced steam conditions. The arrangement includes reheat curtain walls in the upper furnace, a cavity for limestone injection and a downpass with two parallel gas paths. Control dampers located at the bottom of the downpass, bias the flue gas flow to each of the gas paths to control reheat outlet steam temperatures throughout the load range. A single regenerative air heater located downstream of the economizer flue gas outlet is provided to heat both the primary and secondary air.

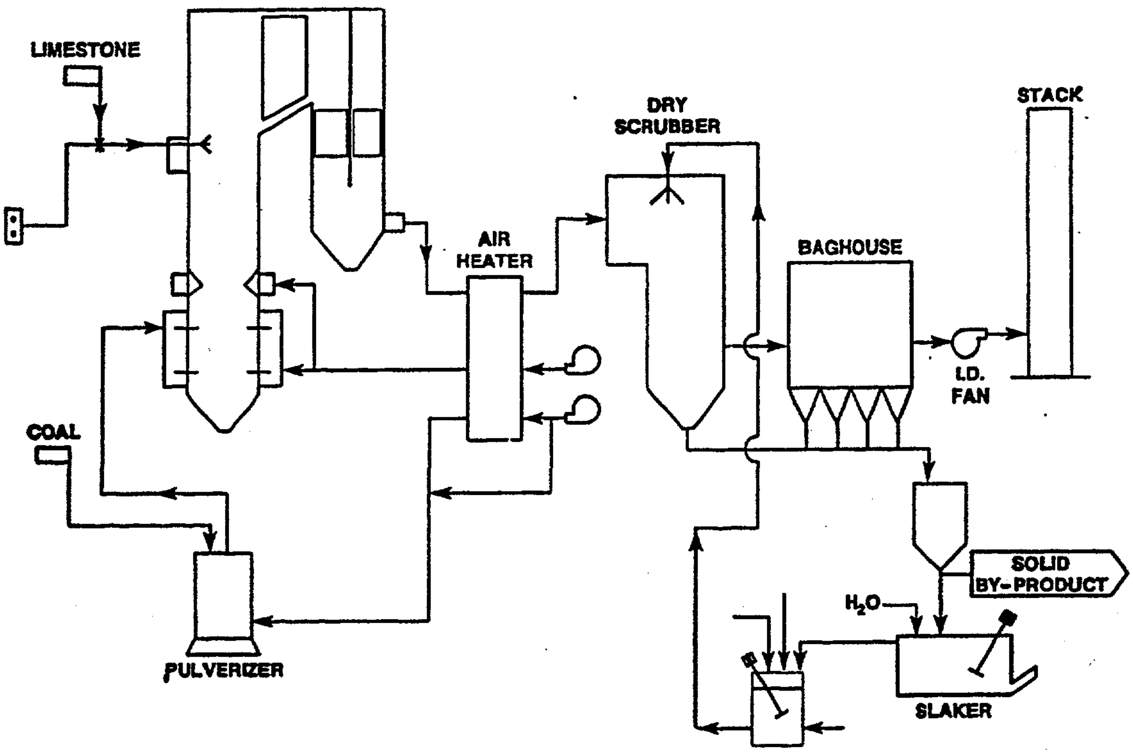


Figure 1 -- B&W Low Emissions Boiler System Configuration

The B&W LEBS concept uses the LIDS process for SO_2, particulate, and air toxics control. It is a limestone-based furnace injection/dry scrubbing SO_2 removal process. The process comprises the cost-effective integration of three commercially-proven flue gas clean-up technologies: furnace limestone injection, dry scrubbing, and pulse-jet fabric filtration. Sulfur dioxide removal occurs in the furnace, dry scrubber, and fabric filter. The furnace limestone injection process facilitates the cost-effective use of a dry scrubber for downstream SO_2 removal by: 1) permitting the use of limestone as the sorbent (as opposed to the more expensive lime used in most dry scrubbing processes), and 2) by reducing the inlet SO_2 concentration to the dry scrubber through in-furnace SO_2 removal. This latter fact permits the LIDS process to be applied to units firing high-sulfur coals.

Control philosophy for the LEBS is to use conventional state-of-the-art solutions wherever possible. However to achieve the emissions and performance goals, several significant new measurements, control elements, and algorithms have been included. Key elements of the advanced control strategy are controlling air and fuel ratios on a per burner basis and active control of the furnace thermal environment. The distributed control system provides analog, sequential control, data acquisition, one or more operator interfaces, and a computer interface for the boiler and BOP control. Several control system enhancements are included in order to allow full integration of the boiler, LIDS and NO_x control systems, in maintaining efficient generating unit operation throughout the load range.

The BOP includes the remaining equipment scope of supply required for a complete and operational generating unit. In order to meet the project's efficiency and cost-of-electricity goals, a steam turbine utilizing an advanced supercritical steam cycle is included. These advanced turbine steam conditions include main steam at 4500 psig pressure and 1100°F superheat, high-pressure reheat, and low-pressure reheat temperatures (4500, 1100, 1100, 1100).

C. Overall Objectives

As mentioned previously, the overall objective of subsystem testing is to develop the design base for and to ensure successful operation of the Proof-of-Concept (POC) Facility in Phase IV. Specific objectives of each subsystem are:

<u>NO_x Control Subsystem</u>

- Advanced low-NO_x burner performance
- Staged combustion utilization
- Corrosion study
- Fuel preparation specification

<u>SO_x/particulate/air toxics Control Subsystem</u>

- LIDS sulfur oxides control
- LIDS particulate matter control
- LIDS system operability and design
- LIDS Air toxics control
- Solid by-product minimization and/or utilization

<u>Controls and Sensors Subsystem</u>

- Unburned carbon monitoring
- Burner coal flow and primary air flow

Details on the objectives, test plan, and test facility design is discussed in the sections that follow.

II. CLEAN ENVIRONMENT DEVELOPMENT FACILITY

A. Description Of Existing Facility

The Clean Environment Development Facility (CEDF), located at B&W's Alliance Research Center, will be utilized as the base LEBS Task 11 Subsystem Test Facility. This large scale, 100 MBtu/hr, state-of-the-art test facility integrates combustion and post-combustion testing capabilities to provide the products and processes needed to meet or exceed the current requirements of the Clean Air Act Amendments of 1990. This size allows for testing equipment with a minimum of scale-up for commercialization.

The facility is sized for a fuel heat input of 100 MBtu/hr when burning a wide range of pulverized coals, #2 and #6 oils, and natural gas. In smaller facilities the complex flow and mixing patterns, and the pyrolysis and char combustion reactions occurring at the flame front do not always result in predictable geometric scaling. The facility has been designed to accommodate either a single burner of 100 MBtu/hr or multiple burners of equivalent total capacity. Baseline and permitting runs have already been performed in the facility with a single, 100 MBtu/hr B&W DRB-XCL® commercial burner.

The LEBS Phase II NO_x Subsystem test effort will employ the advanced low-NO_x burner developed from pilot-scale testing in Phases I and II. The Phase II subsystem testing will provide a fully developed advanced burner at a size close to commercial capacity (typically 100-200 MBtu/hr), virtually eliminating scale-up concerns. The POC demonstration in Phase IV will employ eight burners of 12.5 MBtu/hr capacity each, designed from the experience gained at the 5 MBtu/hr and 100 MBtu/hr levels. Since the burner scale-up issues will be addressed in Phase II, the integration of the burners, the ability to control their individual operation, and optimization of a complete overfire air system must be demonstrated in Phase IV. Previous work in Phase II employing the 5 MBtu/hr and 100 MBtu/hr burners will provide the performance characteristic link to the POC and the Commercial Generating Unit.

The design of the furnace and convection pass is shown in Figure 2. The shape of the furnace results from rotating the firing axis of the large burner 90 degrees from the firing axis of the small burners and furnace exit. The furnace is designed as a water-jacketed box with a refractory lining to maintain the proper combustion zone temperature. The vertical part of the furnace is 13 feet deep by 10 feet wide inside the refractory, and about 44 feet high from the centerline of the large burner to the centerline of the gas exit duct. The furnace tunnel for the single burner is 13 feet wide and extends an additional 20 feet from the furnace shaft to prevent flame impingement on the side or back walls. The furnace extends about 9 feet below the burner centerline and terminates in a hopper. The water jacket extends approximately 4 feet above the top of the furnace to provide for steam/water separation in the jacket. Thus the total external height of the furnace from the apex of the hopper to the top of the water jacket is approximately 62 feet.

The single 100 MBtu/hr advanced low-NO_x burner will be mounted on the north wall of the lower furnace as an extended zone. This zone is 13 feet wide by about 15 feet high at the burner. The roof of this zone is arch shaped and slopes upward toward the vertical shaft at about 30 degrees. The sloped arch roof is required to provide room for gas recirculation above the burner and to accommodate the natural buoyancy of the flame. Beneath the large burner and furnace shaft there is a hopper and slag tank with a water-impounded drag chain conveyor for removing ash and slag. The windbox, which is about 10 feet square, is not shown but will extend out about 6 feet from the front of the furnace.

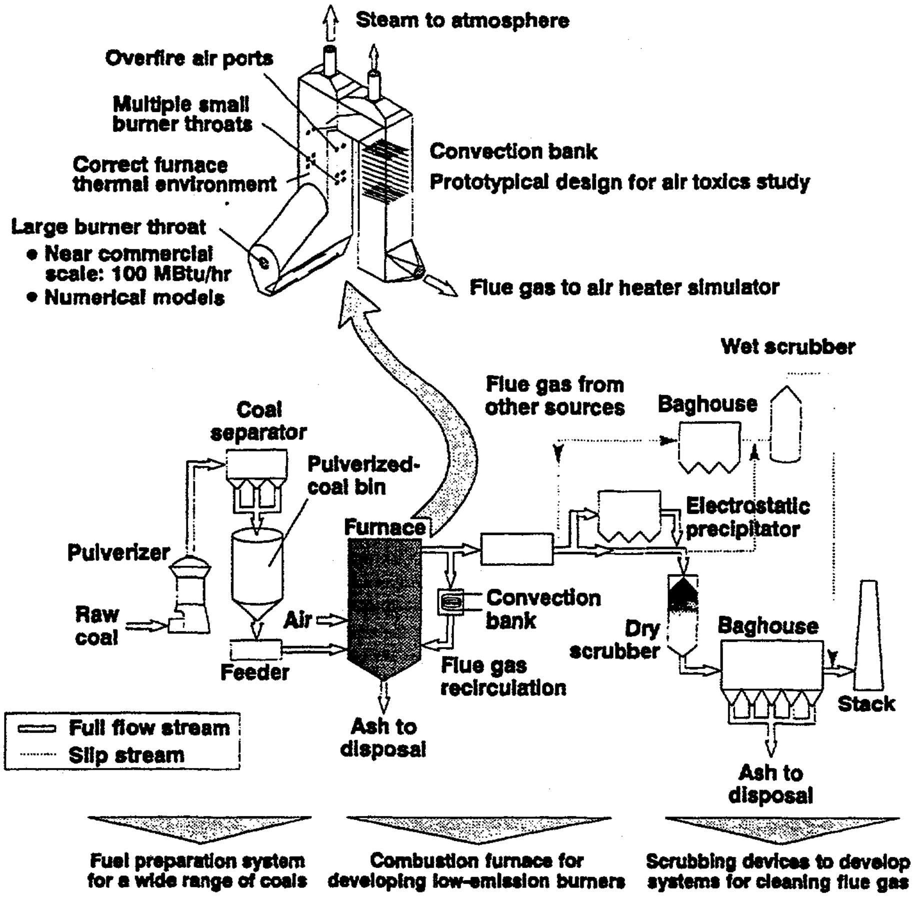


Figure 2 -- CEDF Furnace and Convection Pass

Overfire air ports are located in the furnace side walls at approximately 3 feet above the transition from the burner tunnel to the furnace shaft. The NO_x concentrations can be further reduced by the use of overfire air to create deeper staging of the combustion. The residence time at high temperatures must be kept within critical limits when using overfire air. This residence time may not be easily achieved with the large single burner because of the width and depth established by flame impingement limits with the single burner. In order to optimize the complete overfire air system, the multiple burner system (as in the POC) would be required.

The flue gas from the furnace will pass over a nose or arch that protrudes approximately 35% into the furnace. The nose provides sufficient flow resistance to develop the proper gas flow patterns in the vertical shaft and at the entrance of the convection pass for the large single burner. The gas exit is the full width of the furnace (10 feet) by 12 feet high.

When the single burner is in use, the evolution of flame-generated volatile organic compounds (VOC) and air toxics can be followed as the flue gas cools from flame temperature to a typical emission control device temperature. This is accomplished by taking measurements at various points along the flue gas path from the furnace exit to the inlet of the SO_2 emission control device. Careful control of the gas cooling rate is required to provide a gas time-temperature profile that is similar to commercial units. In this way a representative reaction environment is created for the formation and destruction of NO_x-related species and air toxics. A two-stage cooling process is used to achieve the desired time-temperature history. The first stage is a simulated convection bank while the second stage more closely simulates an air heater.

The convection bank is a 10 x 12 foot water-cooled duct. In order to make the best use of the available space the convection bank has a horizontal section followed by a down flow vertical section. A large number of water-cooled tubes run from the floor to the ceiling of the horizontal section and side to side with an incline of about 15 degrees in the vertical section. The tubes are spaced uniformly across the duct in any given row but the number of tubes per row and the row spacing along the duct is very irregular. This non-uniform tube spacing is designed to simulate the flue gas time-temperature pattern found in commercial boilers. Tube spacing is also influenced by the need to accommodate coals with strong fouling tendencies. Sootblowers are installed to keep the convection pass tubes clean. The flue gas cools rapidly in the initial section of the bank but more slowly in the later parts that simulate the economizer. Sufficient heat transfer surface is provided to cool the flue gas from the furnace exit temperature to about 700°F at the exit.

Following the convection bank the flue gas enters a combination flue gas cooler and air heater. The gas temperature leaving this unit is controlled to a suitable value for the gas clean-up systems. The flue gas is primarily cooled with secondary air through preheating of the air. The outlet temperature is adjusted by independently adjusting the air flow through the upper modules. The simulation of the burner and furnace test zone terminates at the flue gas cooler. Numerous sample connections are located along the gas flow path to follow the formation and destruction of VOCs and other air toxics.

Boiler convection pass and air heater simulators maintain representative conditions through the entire boiler system to facilitate studies of air toxics capture in the LIDS dry scrubber and baghouse. Representative gas phase time-temperature profiles *and surface metal temperatures* are maintained throughout the convection pass. Convection pass metal temperatures are maintained in the 600-100°F range by way of a novel double-walled tube design.

Air and Coal Supply

Pulverized coal is supplied to the burner by an indirect or "bin feed" system so that a wide range of air-to-fuel ratios and fuel moistures can be studied. Separating the pulverizer and burner also allows limited periods of independent operation of the coal preparation and burning units. A B&W EL-56 pulverizer is equipped with a dynamically staged, variable speed classifier so that the effects of coal fineness on NO_x production and unburned carbon can be evaluated.

Preheated primary air picks up the coal and transfers it to a small baghouse that vents the wet air and drops the coal into a pulverized coal storage bin. The bin is equipped with a nitrogen inerting system to prevent bin fires. The pulverized coal can also be sent directly from the pulverizer to the burner when burning fuels for which the pulverizer output matches the required feed rate and air/fuel ratio.

Pulverized coal is withdrawn from the bottom of the bin by a flow control device and picked up in a transport air stream that carries it to the burner. The as-fired moisture level can be varied by spraying water into the transport air upstream of the pick-up point. In order to obtain maximum flexibility and control, separate fans and air preheaters are used for the primary air to the pulverizer, transport air from the pulverizer to the burner, and secondary air to the burner or overfire air ports.

Post-Combustion Emission Control

From the flue gas cooler the gas enters a dry scrubber to control sulfur dioxide emissions. Although this system can be used to advance dry scrubber technology, its current primary purpose is to allow the facility to meet air emission regulations. The dry scrubber is a vertically oriented, 14-foot diameter by 60-foot tall tower (including inlet and exit transition sections) constructed of carbon steel. Flue gas enters the top through an expansion containing flow straightening devices.

An atomized slurry is introduced through a single B&W DuraJet™ atomizer located to provide uniform spray coverage in the vessel. The B&W DuraJet™ atomizer is used in commercial dry scrubbing and humidification systems. The atomizer not only provides a finely atomized slurry, but also acts as a mixer to ensure intimate contact between the hot entering flue gas and slurry, maximizing SO_2 removal and drying. The atomizer is mounted in a shield air tube at the scrubber inlet allowing for naturally aspirated vent air flow. A reagent preparation system is designed to wet hydrated lime and prepare slurry for injection into the dry scrubber. The flue gas, along with the dried particulate, travels down the chamber and turns 180° into an air outlet duct. The outlet duct is fitted with a sloped cone to minimize solids dropout in the duct.

Flue gas exiting the dry scrubber is ducted to a pulse-jet fabric filter baghouse. The baghouse consists of six modules arranged in a three-by-two array. Each of the six modules contains 42 full-size bags for a total of 252 bags in the baghouse. The air-to-cloth ratio is adjustable from 4:1 to 6:1 at full load by blanking off modules. The entering flue gas is distributed to the bottom of each of the six modules through a tapered inlet manifold. Manually-operated butterfly dampers are used for module isolation. The clean gas exits each module at the top and is collected in a tapered clean gas manifold. Pneumatically-operated poppet valves are utilized for module outlet isolation.

The pulse-jet cleaning system is designed to permit either on-line or off-line cleaning in either manual or automatic operating modes. For additional flexibility, in the automatic mode the fully adjustable cleaning cycle may be initiated on either baghouse pressure differential, timed, or combined pressure differential/timed basis. The solid byproduct dislodged from the bags is transferred from the baghouse by a pneumatic conveyor system to an ash silo for disposal.

Existing post combustion emissions control instrumentation includes: dry scrubber and baghouse outlet temperature, dry scrubber skin thermocouples to monitor deposition, atomizer slurry and air pressure gauges, baghouse pressure drop across each of the six baghouse modules, and a continuous emissions monitor at the stack.

B. Permit Discussion

The CEDF is currently operating under a Permit to Install (PTI) which was issued on November 17, 1993. During the first week of January, 1995, EPA source emission stack testing was successfully completed. We anticipate issuance of a Permit to Operate from Ohio EPA in the near future. Until a Permit to Operate is issued, we will continue to operate under our existing PTI. The LEBS subsystem testing will comply with the anticipated permit to operate. Further, the Alliance City Publicly Owned Treatment Works (POTW) has given approval to use the City's sanitary sewer for all wastewaters to be discharged from the CEDF. The permission was granted during a meeting with the City on April 13, 1994.

III. NO_x SUBSYSTEM

The goal of the NO_x Subsystem is to achieve continuous operation of the Low Emissions Boiler System (LEBS) at NO_x emissions at or below 0.10 lb/MBtu over a range of loads typical of a base-loaded generating plant. This goal places practical constraints that must be considered in the NO_x subsystem design. Not only must the boiler be designed to achieve time-temperature mixing histories that minimize NO_x, it must also be designed to operate that way throughout its working lifetime. Therefore, NO_x minimization strategies must be integrated into the control systems for every boiler component from the pulverizers to the stack. Low NO_x must be maintained in spite of pulverizer maintenance, steam temperature variations, and start-up or shutdown, to name only a few examples of issues faced by boiler operators every day. Furthermore, these goals must be met without increases in carbon loss and CO emissions from the levels achieved with current low-NO_x combustion systems. Therefore, the NO_x Subsystem requires not only sound mechanical designs of burners, furnace surface, and staging air/fuel injectors, but also sensors and software to allow control of their operation.

Without overfire air, low-NO_x burners alone will probably not achieve the NO_x B&W team goal of 0.10 lb/MBtu and may not meet the DOE program goal of 0.20 lb/MBtu. In fact, a breakthrough in low-NO_x burner technology will probably be required to reach this goal without operating a substantial part of the furnace under reducing conditions. Such a breakthrough is not unreasonable to expect based on development at Babcock & Wilcox, however, moderate staged combustion may be required even with such a breakthrough in technology.

In Phase I of the LEBS program, a thorough review and assessment of potential advanced technologies and techniques for the control of emissions and a review of boiler design options was performed by the NO_x Subsystem Team. This led to the initial LEBS conceptual design. A number of uncertainties arose from the conceptual design. In order to reduce and/or eliminate these uncertainties, a Research, Development, and Test (RD&T) Plan was developed. This plan detailed how information needed to resolve the design uncertainties would be obtained through engineering analysis, experimental testing, and numerical modeling. The results of those activities were used to revise the LEBS conceptual design and develop the Preliminary Engineering Design. Research and development continued into Phase II with further engineering analysis, experimental pilot-scale testing, and numerical modeling. The results of these activities helped to further define the LEBS design for the Proof-of Concept (POC) Facility and the Commercial Generating Unit (CGU). To ensure successful operation of the POC and CGU, testing various aspects of the NO_x Subsystem at near full scale was determined to be necessary.

The NO_x Subsystem Testing will be performed in B&W's state-of-the-art 100 MBtu/hr Clean Environment Development Facility (CEDF). Testing will allow for the reduction and/or elimination of any remaining design uncertainties before finalizing the POC and CGU designs. Testing at this scale will allow for further development while reducing any uncertainties associated with scale-up. Numerical modeling predictions can be validated at the Subsystem scale which gives further validation of performance predictions for the Commercial Generating Unit.

A. Specific Objectives

Advanced Low-NO_x Burner Performance

As previously stated, the goal of the Low Emissions Boiler System (LEBS) is to achieve continuous operation at NO_x emissions at or below 0.10 lb/MBtu over a range of loads typical of a base-loaded generating plant. An aerodynamically air-staged burner (AASB) will be utilized for NO_x control. A burner size of 150 MBtu/hr will be used for the LEBS commercial generating unit in an opposed wall configuration in a three wide by four high burner arrangement.

Neither the program requirement of 0.2 lb/MBtu (150 ppm) nor the team goal of 0.10 lb/MBtu (75 ppm) has been met yet in a commercial installation with a coal similar to the required design fuel. A major breakthrough in the performance of an AASB and/or advanced overfire air (OFA) system is needed to obtain these NO_x emission objectives.

The 100 MBtu/hr CEDF will be utilized for the NO_x Subsystem testing. The facility is designed to obtain temperature and residence time profiles similar to a commercial unit. This allows for accurate comparison for emissions, unburned carbon, and temperature measurements. In this facility, the advanced low-NO_x burner can be tested at near full-scale which will reduce the uncertainties associated with scale-up and development.

Three general areas of concern are associated with the performance of the low-NO_x burner. These uncertainties deal with the control of NO_x, flame stability, and the impact on the boiler efficiency.

NO_x Control - The intent of the low-NO_x burner design (and the staged boiler) is to limit O_2 availability during devolatilization since this governs the conversion of fuel-bound nitrogen species to NO_x in the ignition zone. NO_x formation will depend on swirl, coal spreader design, coal nozzle geometry, and burner zone stoichiometries. Testing the advanced low-NO_x burner at the subsystem scale will allow for final development and validation of a burner with the capability of reaching the project NO_x goals without sacrificing the boiler efficiency or other combustion parameters. Data collected can be compared to the pilot-scale test results and the numerical modeling predictions. This near full-scale burner testing will allow for any necessary adjustments to be made before finalizing the Proof-of-Concept and Commercial Generating Unit designs.

Flame Stability - It is uncertain if the flame will be stable at the low stoichiometric ratio necessary to meet the NO_x goals. If the burner can not be stabilized at this low stoichiometry, another NO_x control strategy will have to be implemented. The objective of the flame stability testing for the low-NO_x burner development is to demonstrate operation with advanced staging while maintaining a stable flame. Combustion testing will be performed to see the effect of the lower burner stoichiometry on the flame stability at full and partial load. Results from the flame stability tests will reveal how stable the near full-scale advanced low-NO_x burner operates when at substoichiometric conditions. This information can be used to help define the staged combustion scheme used for the Commercial Generating Unit.

Boiler Efficiency Impacts - The general aims of maximizing combustion efficiency and minimizing emissions can be conflicting. Combustion efficiencies are maximized at, or close to stoichiometric mixing conditions, where the highest temperatures are achieved. These high temperatures lead to the maximum formation of NO_x, however, carbon monoxide, unburned hydrocarbons, and particulates are minimized. Optimization can only be achieved by very careful control of air/fuel ratio and temperature levels throughout the system.

The objective of testing the boiler efficiency impacts as part of the low-NO_x burner development is to make sure that the technologies implemented to control the NO_x level do not adversely affect the unburned carbon losses, the CO emissions, or the efficiency of the boiler. The testing proposed to evaluate the effect of the burner on the efficiency of the boiler is to complement the work being done for the development of the LEBS advanced low-NO_x burner. The effect of the advanced low-NO_x burner NO_x reduction schemes on unburned carbon, CO emission, and boiler efficiency will be determined from the Subsystem Testing. This information will be used along with the data collected from the NO_x Control testing to finalize the advanced low-NO_x burner design for the POC and CGU.

Staged Combustion

In order to meet the B&W team NO_x emission goal of at most 0.10 lb/MBtu, furnace staging will be required. However, the extent of staging needed is unknown. Three different staged combustion strategies have been considered; conventional overfire air (OFA), advanced OFA, and reburning. Conventional OFA ports have proven to reduce NO_x emissions. However, if the advanced low-NO_x burner can not make a significant breakthrough in the area of NO_x emissions an advanced OFA system will be required. The advanced OFA strategy is defined as firing the burner zone at a stoichiometric ratio of 0.7 to 0.9 and quenching the gas temperature prior to OFA addition as a consequence of boiler design. This strategy has a moderate level of risk for achieving the NO_x emission levels.

Advanced Overfire Air - The NO_x reduction approach taken in the preliminary concept design suggests that the NO_x emission target will be met with an advanced OFA strategy even without significant NO_x reduction gains from the burner. However, the advanced OFA system still needs further refinement through modeling activities in Phase II. There are also concerns in regards to excessive unburned carbon losses, burner instability, furnace corrosion due to sulfur attack, and the uncertainty of NO_x levels.

The NO_x emission level must also meet the NO_x requirements over the entire load range. The delayed mixing of overfire air could increase the ash carbon content, while decreasing the NO_x. Carbon content of the fly ash almost always increases when low-NO_x combustion systems are applied to existing boilers originally designed with turbulent burners. This increase is inevitable since the low NO_x retrofit generally reduces flame temperature, causes slower mixing, and has less air available at the burner. Coal reburning can further exacerbate the problem since char combustion cannot be completed until the overfire air is completely dispersed in the upper furnace. In a retrofit, there is often not enough residence time in the upper furnace to mix and burn the char at such low temperatures. Not only is the efficiency decreased, but fly ash disposal problems can arise due to the high carbon content.

One objective of subsystem testing is to further develop and partially validate the advanced overfire air system. The Clean Environment Development Facility (CEDF) will be used for testing the overfire air system. The burner stability and performance and the OFA control will be evaluated. Downstream mixing will not be evaluated during the subsystem testing, but will be addressed through numerical modeling. The single and multiple burner arrangements with the overfire air ports will be modeled and evaluated in Phase II. The results from the modeling runs will be used to further refine the multiple burner and overfire air arrangement for the POC demonstration. Even though downstream mixing will not be evaluated during the subsystem testing, OFA ports are required for carbon burnout. Sensitivities to various parameters will be explored in conjunction with the advanced low-NO_x burner testing. Testing will partially show the effect of the implementation of an OFA system on the scaled-up version of the advanced low-NO_x burner.

Corrosion

Accelerated corrosion on the lower furnace walls of coal-fired boilers is a concern for low-NO_x combustion technologies. Burning coal substoichiometrically can generate reducing combustion gases. When a high-sulfur coal is burned, the combustion gases become high in sulfur potential (i.e., the gas being sulfidizing) and low in oxygen potential (i.e., the gas being reducing). The sulfur may exist in the combustion gases as H_2S and COS. The shift of the chemical potential from oxidizing to reducing often promotes higher corrosion rates on alloy surfaces. Therefore, the material issues must be fully addressed as a part of the successful implementation of the low NO_x combustion technologies.

Reducing Conditions - Burning Illinois #6 high-sulfur coal in the LEBS at an air/fuel stoichiometric ratio near 0.7 can result in a high H_2S concentration in the combustion gases. Even though the temperatures at the waterwall surfaces where corrosion actually takes place are significantly lower than those of combustion gases, the H_2S concentration may still be too high for conventional boiler operation. The level of H_2S concentration in the lower furnace is likely to accelerate metal wastage. Both B&W's laboratory and field studies suggested that the corrosion must be a concern for the lower furnace of LEBS.

The wastage of furnace walls in LEBS in contact with the low NO_x combustion gas may be further aggravated by the higher metal temperatures compared to those in conventional PC-fired boilers. B&W's laboratory studies confirmed that the low NO_x corrosion wastage of boiler tubes increases exponentially with metal temperature. This implies that an increase in the metal temperatures of waterwalls in LEBS, resulting from a higher steam temperature and supercritical pressure, can lead to a noticeable increase in metal wastage. Therefore, the impact of high metal temperatures on waterwall wastage in the combustion zone of LEBS needs to be evaluated.

Because the development of low-NO_x combustion technologies is relatively recent, the corrosion data relevant to the LEBS low-NO_x operation are limited. As a result, generation of additional corrosion information for materials selection in Phase II of the LEBS program is essential. Subsystem testing will be used to study the corrosion environments in the lower furnace so that the LEBS Commercial Generating Unit (CGU) can be better defined.

Convection Pass Fouling/Erosion. The impacts of the LIDS limestone injection process on furnace and convection pass ash deposits and, subsequently, on boiler heat absorption and thermal performance must be quantified. Previous studies have indicated that heat absorption in the high temperature (radiant) banks of the boiler convection pass is impacted by the presence of the sorbent. Sufficient information will be developed to permit the LEBS plant boiler system to be designed for long-term, reliable operation at high thermal efficiency.

Fuel Preparation

The design coal for LEBS is an Illinois #6 bituminous coal. Overall, the design coal is a challenging coal to burn and was selected to provide a meaningful assessment for the SO_2 and NO_x emission reduction technologies. The LEBS CGU calls for the coal to be delivered to the powerhouse silos at a 1-1/2-inch topsize. The LEBS CGU also specifies that four pulverizers will be utilized with a conventional roller and race, and an advanced classifier each feeding a group of six burners. The requirements of the fuel preparation system are to be determined by the NO_x Subsystem Team as input to the design and implementation effort of the Boiler Subsystem Team. Two areas of concern for the NO_x Subsystem are the functional specifications for the pulverizer and the primary air-to-fuel ratio. Both areas can influence the NO_x emissions and the unburned carbon in the fly ash.

Functional Specifications for Pulverizer - The high-speed rotating classifiers on the pulverizers are to limit the size of the fuel to 90 to 95% through 200 mesh and 100% through 100 mesh. The current state-of-the-art NO_x control systems for pulverized coal units utilize a fuel sizing of 70-80% through 200 mesh. It is believed that this increased fineness will play an important role in the reduction of emissions and unburned carbon losses. The exact level of fineness needed, however, is unknown. The smaller particle sizing provides increased surface area which promotes more rapid and complete combustion. Many of the processes used by NO_x combustion control systems (such as fuel and air staging) act in opposition to efficient carbon burnout. High fuel fineness can help to offset potential increases in unburned carbon efficiency losses. The reduced particle sizing also improves the NO_x reduction performance of current low-NO_x burners. Rapid burning enhances the NO_x reducing effect of the complex combustion principles utilized by low-NO_x burners.

Subsystem testing will be performed to determine the effect of coal fineness on the 100 MBtu/hr scaled advanced low-NO_x burner. This information is needed for the development of an advanced pulverizer that is capable of obtaining a greater level of fineness and reduced top size than current pulverizers for implementation in the LEBS Commercial Generating Unit Design.

Primary Air/Coal Ratio - The current choices for conveying the pulverized coal to the burners are:

Primary air or flue gas at 2 lb air/lb coal (mill characteristic)
Firing pulverized coal from storage at variable lb air/lb coal.

These choices are the current means used to achieve an even distribution of temperature and gas composition. The primary air (PA) to coal ratio could be minimized by having a higher pulverizer outlet temperature, which would help in obtaining the desired fineness. The optimum primary air to coal ratio in connection with the fineness of the coal, but with pulverizer constraints, needs to be determined.

In order to meet optimum firing conditions, the primary air/coal ratio on a per burner basis must be determined. The object of the primary air (PA) to fuel ratio test program is to determine the performance sensitivity to the PA/fuel ratio. Testing will be performed at the subsystem level to determine the optimum practical primary air to fuel ratio for incorporating into the POC and CGU designs.

B. Facility Modifications Needed to Meet Objectives

System Description

Subsystem Testing will be carried out in the Clean Environment Development Facility described in Section II. This existing facility has all the necessary coal preparation and emission control equipment needed to support the NO_x Subsystem Testing. However, some modifications to the existing facility are required. A new 100 MBtu/hr Advanced Low-NO_x Burner, an Overfire Air System, and a Corrosion Study System will be designed, fabricated, and installed during Tasks 9 and 10 of Phase II. These systems are described below.

Advanced Low-NO_x Burner System - A 100 MBtu/hr advanced low-NO_x burner will be designed fabricated and installed on the CEDF. The burner will be scaled-up from the pilot-scale burner developed in Task 7 of the LEBS project. The current air and fuel systems on the CEDF are adequate to handle the advanced low-NO_x burner and therefore, no modifications will be needed to support testing.

The advanced low-NO_x burner operates on the principle of delayed combustion. Studies devoted to reducing NO_x emissions from pulverized coal reveal that the formation of volatile NO_x is sensitive to changes in early mixing of fuel and air. The advanced low-NO_x burner takes advantage of this sensitivity by diverting air away from the core of the flame, reducing local stoichiometry during coal devolatilization, thereby reducing initial NO_x formation. The burner is equipped with a set of multiple fixed-spin vanes located in the outer air zone to enhance distribution of air around the periphery of the burner. Adjustable vanes are located in both the outer and inner air zones to impart proper spin to the secondary air for flame stability and optimum mixing of fuel and air.

Overfire Air Port System - One row of two overfire air (OFA) ports will be installed on both sides of the CEDF. The location will be three feet above the transition from the burner tunnel to the vertical shaft. This location allows for introduction of the overfire air for carbon burnout without interfering with the gas flow patterns in the burner tunnel. Burner performance and stability at low stoichiometries can be explored with this OFA port arrangement.

B&W's unique dual-zone overfire air ports will be installed on the CEDF. The ports provide even distribution of overfire air. The ports are equipped with sliding dampers, spin vanes and air flow measurement devices to enable flow balancing during commissioning of the equipment. The sliding air damper may be automated to control the air through each port. The spin vanes control the swirl or tangential velocity and flare of the air pattern through the OFA port and into the furnace.

The air for the OFA ports will be taken from the secondary (or combustion) air. Metering devices will be installed to control the air flow to the burner and to the OFA ports. The metering devices will be connected to the data acquisition system for data collection.

Corrosion Study System - The corrosion probes for the lower furnace of the CEDF consists of tube segments of five different alloys (T2, T22, T9, 304SS, and 310SS). The alloys will be exposed to the corrosive combustion gas generated in the burner zone. The probes will be internally cooled with an air/water mixture during the test to control the metal temperatures continuously. Chordal thermocouples will be attached to several tube segments from the inner surfaces of the probe to monitor the metal temperatures continuously. Ash deposit will be collected on the cooled surfaces for chemical analysis after the test. Gas samples will also be taken periodically through a central tubing of the probe during the corrosion exposure. The gas samples will be analyzed by gas chromatography for its H_2S concentrations.

<u>Equipment List</u>
This section describes the components of the existing facility that will be used in the Phase II, Task 11 - Subsystem Testing demonstration along with the equipment that will be added in Tasks 9 & 10. A more complete description of the present facility is given in Section II (Figure 2).

Furnace - The CEDF furnace is a natural circulation, water cooled, refractory lined combustion chamber capable of handling heat inputs up to 100 MBtu/hr in a single or in multiple burners. As it is presently configured the furnace consist of two parts, a tunnel to accommodate the large burner followed by a vertical shaft that simulates the residence time-temperature history of a commercial unit. The large burner tunnel is 13 feet wide by 15 feet high at the burner with an arched roof that slopes upward at about 30 degrees toward the shaft. The tunnel is about 20 feet long. The slope allows for the natural buoyancy of the flame without impingement on the walls. The shaft is 13 feet wide by 10 feet deep with a total height of 44 feet from the burner centerline to the exit centerline. The refractory in the tunnel, lower shaft, and upper shaft, was selected so that the flue gas temperature is about 2900°F in the lower shaft and 2250°F at the exit plane.

Following the furnace is a convection pass that simulates the flue gas time-temperature history and tube metal temperature of a typical commercial unit. The convection bank is a 10- by 12-foot duct that has horizontal and down flow sections to conserve space. A large number of water cooled tubes run from floor to ceiling in the horizontal section and side to side with an incline of 15° in the vertical section. The tubes are uniformly spaced across the duct in any given row but the number of tubes per row and the row spacing along the duct are irregular. Since cooling is achieved with boiling water at about 212°F and not superheated steam, a double-walled tube design with an air gap is used to achieve representative metal temperatures (600 to 1100°F). All of the water evaporated in the furnace and convection bank water jackets, approximately 180 gpm, is vented to the atmosphere.

The flue gas from the convection bank passes through a two-stage gas cooler and is sent to the dry scrubber. The first stage cools the gas from about 700°F to about 380°F by heat exchange with the secondary air in a three-pass plate heat exchanger. The second stage further cools the flue gas by heat exchange with a waste air stream supplied by a vent air fan. The present vent air fan and two-pass vent cooler will lower the flue gas temperature to about 300°F entering the dry scrubber. The exit gas temperature can be regulated by venting secondary air and adjusting the flow of vent air.

Coal Preparation System - The equipment in the coal preparation system is all standard and commercially-available and is sized for a maximum coal flow rate of about 7.5 tons/hour with a low-Btu fuel such as North Dakota lignite. As-received coal, with minimal drying to facilitate handling if required, is elevated to a 50 ton raw coal storage silo. A gravimetric feeder measures the flow to a B&W EL-56 pulverizer equipped with a DSVS™ (dynamically staged, variable speed) classifier. The pulverizer is capable of producing a coal fineness of 70 to 90% through 200 mesh. The pulverized coal (PC) is sent to a baghouse that separates the coal from the humid air and discharges it into a 16 ton storage bin. Using the intermediate bin decouples the pulverizer from the burner to allow maximum flexibility and control of each component. A second gravimetric feeder regulates and measures the flow of pulverized coal into the primary air stream which carries it to the burner. This PC feeder has a capacity of 8 tons/hour.

Air Supply System - In order to obtain maximum flexibility and control, separate fans and air heaters are used to supply air to the pulverizer, burner primary air and burner secondary air. One fan supplies air through a direct fired air heater to the pulverizer to dry the coal and transport the PC to the baghouse. A second fan with a variable speed motor supplies primary air to the burner. An indirect fired air heater and humidifier to replace moisture lost in the pulverizer permits adjustments over a wide range of air-to-fuel ratios while maintaining the primary air temperature and moisture content of a direct fired PC system. The primary air fan is capable of supplying up to 40,000 lb/hr of air at 45 inches of water head.

A third fan with a variable speed motor supplies secondary air to the burner. This air is heated to about 500°F in the secondary air heater by the flue gas as described above. The air can be further heated to about 700°F by an indirect fired trim heater. This fan is capable of supplying 90,000 lb/hr at 45 inch of water head.

Environmental Control Systems - The flue gas from the gas cooler goes to a dry scrubber to control SO_2 emissions. The dry scrubber is a 13.5 foot diameter by 60 foot tall tower, including top inlet and bottom outlet transition sections. A finely divided atomized slurry of hydrated lime is sprayed into the tower by single axially mounted B&W DuraJet™ atomizer. As the gas and liquid flow co-currently through the tower the lime reacts with the SO_2 and the slurry water evaporates leaving calcium sulfite and fly ash as a fine suspended powder.

The dust-laden gas from the dry scrubber enters the baghouse for particulate removal. Ash from the six module, pulse-jet cleaned baghouse drops through rotary valves into two parallel drag chain conveyors. The ash is transferred to a common pickup point and then pneumatically carried to an ash silo.

An induced draft fan with variable inlet vanes draws flue gas from the baghouse, controls the furnace draft, balances pressure losses. The gas is discharged through a 200 foot tall stack to get maximum dispersion and ensure compliance with ground level concentrations. The induced fan has the capability to handle

120,000 lb/hr of air at 45 inch of water head.

Overfire Air Ports - The overfire air system that will be used in the Subsystem testing is an advanced version of the Dual-Zone NO_x Port Assembly currently used for staged air admission in PC-fired boilers. The system will use 4 ports, 2 on each wall, above the transition of the burner tunnel to the vertical shaft. The Dual-Zone Assembly creates a high velocity core air zone to achieve jet penetration and an outer air zone with adjustable spin vanes to induce mixing. The throat diameter of the ports will be about 14 inches.

Overfire Air Port Windbox - Each row of overfire air ports will have a common windbox to serve both air ports. The windbox will be similar to the burner windbox. Air from the secondary air trim heater discharge will be supplied to the windbox. The overfire air flow will be a maximum of 20% of the total secondary air flow.

Advanced Low-NO_x Burner - A 100 MBtu/hr advanced low-NO_x burner will be fabricated and installed in the CEDF. The dimensions of the burner will be sized to the dimensions of the existing windbox, air and fuel supply lines, and the burner throat opening in the furnace.

Material Balance

The material balance is based on firing the Illinois #6 LEBS design coal in the CEDF with the dry scrubber in service. The material balance is in Appendix A.

General Arrangement Drawing

The general arrangement drawing for the NO_x Subsystem Testing is in Appendix A.

P&ID Drawing

The process and instrumentation drawing for the NO_x Subsystem Testing is in Appendix A.

C. Test Plan

Tests to be Performed

Parametric Testing on the CEDF for the NO_x Subsystem; advanced low-NO_x burner performance, staged combustion utilization, corrosion study, and fuel preparation specification, will occur in parallel efforts when applicable. Optimization of parts and/or configurations of one system will be used in conjunction with those of others. Each system has its specific goals, however, some of the data is important to numerous systems.

Advanced Low-NO_x Burner - Testing of the advanced low-NO_x burner will include parametric testing and the testing of various hardware components. The parametric testing will consist of variations in load, excess air, and burner settings. Adequate instrumentation will be installed on the CEDF to achieve the test objectives and record all settings. Flows of air, coal, and water to the unit will be measured and recorded. Temperatures and pressures in the flue gas path will be recorded by permanently installed thermocouples and transducers. Gas compositions will be continuously measured leaving the furnace via dedicated gas sampling and conditioning trains. Data will be collected by a data acquisition system (DAS). Pertinent values will be calculated and displayed for operator control. The maximum, minimum, and mean data values for each test condition will be calculated on-line. The furnace will have numerous ports in the side wall through which probes could be inserted for temperature, char, and gas sample traverse which would provide data for model verification, including local gas temperatures and species (NO_x, CO, CO_2, O_2, H_2S), and unburned carbon data.

Staged Combustion - The test program for the overfire air staging will parallel that of the advanced low-NO_x burner testing. The burner stoichiometry will be varied over conditions tested during the parametric testing. The stack gas emissions, local combustion gas temperature data, and unburned carbon data will be collected along with the overall combustion performance and flame stability.

Corrosion - Cooled corrosion probes will be designed and fabricated. These probes will be exposed to the low NO_x combustion gases during the CEDF testing. One of the probes will be installed through the furnace wall in the combustion zone of the CEDF, simulating the fireside corrosion occurring in the lower furnace of the LEBS plant design. The second corrosion probe will be installed in the high temperature banks of the boiler convection pass. Because the testing in the CEDF is expected to be short, the corrosion-rate data are probably not representative of long-term exposure in the LEBS plant. However, the information will be extremely useful for understanding the early stage of the corrosion processes.

The primary functions of the corrosion probe are to define the corrosive environments and collect the ash deposits in the CEDF. Ash deposit will be collected and its chemistry will be analyzed. Attention will be given especially to the layer of deposit adjacent to the metal surfaces, which is likely to govern the corrosion mechanism. Chordal thermocouples will be fabricated in the corrosion probes so that continuous monitoring of the metal temperatures can be made. The compositions of important species in the flue gases will also be analyzed by on-line analyzers and a gas chromatograph.

Fuel Preparation - The level of fineness of the coal will be varied for a specific set of tests while the system's emissions and operating conditions are being monitored. These tests will be performed at similar conditions to the advanced low-NO_x burner and staged combustion tests. The capabilities of the pulverizer will be investigated, along with the effect of the coal fineness level on the cost and plant efficiency as a result of this testing.

The primary air to fuel ratio will also be varied during some of the testing of various parameters with the advanced low-NO_x burner and staged combustion tests. Data similar to that describe previously in the advanced low-NO_x burner development will be taken.

Data Acquisition

Voltage signals from instruments, sensors, and metering devices are collected, converted to a digital signal, and stored by the Data Acquisition System (DAS). STARS/LabVIEW software is utilized to convert these signals to engineering units for on-line real time display in tabular or graphical form at time intervals specified by the operator. Derived quantities such as fuel input (load) and air flow are calculated utilizing other measured instrument values converted to engineering units. The fuel and combustion flows are measured by the DAS electronically utilizing pressure transducers and thermocouples at the flow orifices. Raw voltages from these devices are converted to static pressure, pressure drop, and flow temperature at the orifice by utilizing calibrations based on reference signals. Engineering units for flow are calculated with a calibrated flow orifice equation expressing flow as a function of the above variables.

Data Analysis and Reduction

Advanced Low-NO_x Burner - The data collected from the advanced low-NO_x burner testing on the CEDF will be reviewed after testing. Data will be reduced, plotted, and compared with pilot-scale burner testing results. The information will be compared with modeling predictions and used to find the optimum burner configuration and settings to achieve the lowest level of NO_x not adversely affecting other combustion parameters. Recommendations, as a result of testing, will be given towards any possible modifications of the NO_x Subsystem. These recommendations will be used in re-evaluating the advanced low-NO_x burner design for the POC Test Facility and the Commercial Generating Unit.

Staged Combustion - The flame stability results obtained from the Subsystem Testing will determine what the limitations are of utilizing the advanced OFA ports as the method of staged combustion for achieving the low levels of NO_x required by the project. The data collected will be taken in conjunction with that obtained for the advanced low-NO_x burner testing and will be analyzed in the same fashion. The test results will be used in conjunction with results from the numerical modeling to refine the multiple burner and overfire air port designs for the Phase IV POC facility.

Corrosion - Wastage of the exposed alloys and coatings on the corrosion probes will be carefully examined and the corrosion rate will be determined. Cross-sectional metallographic examinations will also be performed using SEM/EDX and microprobe analyses to determine the morphologies of corrosion products, their chemical compositions, and probable mechanisms of attack.

Fuel Specifications - The coal fineness data will be reviewed so that a coal fineness level can be determined for the Commercial Generating unit that is the most beneficial in terms of NO_x emission, unburned carbon, plant efficiency, and cost.

The optimum practical air/fuel ratio will be determined and compared to the requirements of the NO_x and SO_2 Subsystems. This information will be used as input to the Proof-of-Concept Test Facility and the Commercial Generating Unit Designs.

Start-up and Shutdown Procedures

Subsystem Testing on the CEDF for the NO_x Subsystem will be composed of a series of parametric tests. Parametric testing of load, excess air, and burner settings will follow the same pattern daily for various hardware changes. The hardware changes will occur during the night shift and then the furnace will be brought on-line for testing during the day. The following covers the start-up and shutdown procedures that will be followed for the NO_x Subsystem Testing. All systems will be checked for operability during an initial shakedown period.

Start-up - Start-up of the facility will begin with a walk down of the unit to ensure components are ready. One operator will be in the control room, while another is at each major piece of equipment during start-up of the component. The baghouse compressor will be brought on-line first. The water level for the furnace, convection pass, and slag conveyor tank will then be checked and adjusted for an adequate level. Next, the I.D. fan will be started with minimal flow, and the scanner seal air blower will be initiated. The secondary air fan will then be started at a low rate. The I.D. fan can be set to automatic while the secondary air flow rate is increased to approximately 40% of the total air flow. At this time, the Burner Management System (BMS) will begin a purge if all permissives have been met. After the purge is complete, the gas lighter will be ignited. The unit will be heated up with the lighter for one hour. The primary air fan can be started only after the gas lighter is in service. After the gas lighter has been in service for approximately one hour, the auxiliary gas spud can be started at a minimum firing rate. The secondary air trim heater will be brought into service next. The controller output will be slowly brought to the desired temperature required for testing once the unit is near operating conditions. The burner primary air heater will then be brought into service and the temperature slowly increased to the testing set point. The slag conveyor will be started before firing coal. The gas firing rate is steadily increased to the maximum firing rate. This will be maintained until the unit temperatures stabilize at the convection pass inlet and the dry scrubber inlet. The temperatures at the dry scrubber should be over 200°F and at the baghouse over 160°F. The boiler feedwater pumps can be started at this point. Three of the six baghouse compartments will be brought into service after reaching temperature and prior to firing coal. While maintaining adequate primary air flow to the burner, coal firing can be initiated. The coal flow rate can be increased while still maintaining maximum gas firing. As the dry scrubber outlet temperature increases to 240 to 250°F, the lime slurry pump will be started at a minimum rate. The coal firing rate will slowly be increased while the gas firing rate is slowly decreased. The lime slurry pump will be slowly increased to maintain a SO_2 emission of 1.2 lb SO_2/MBtu and dry scrubber temperatures. Coal firing will be brought up to full load, while gas firing is discontinued. Once the furnace reaches equilibrium, the parametric testing will begin.

Shutdown - There are two types of shutdowns for the CEDF. The first is a short term shutdown to keep the unit hot during burner hardware changes. The second type is shutdown for maintenance or when not intending to refire the unit in a short period of time. For both types of shutdown, the coal firing rate will be reduced to 60 MBtu/hr, at which time the gas lighter will be placed into service. This level will be maintained for approximately one hour. The auxiliary gas burner can be brought into service while the coal burner is further reduced until brought out of service. Once coal firing has stopped, the primary and secondary air heaters are removed from service along with the dry scrubber and baghouse. The auxiliary gas should be reduced to 30 MBtu/hr for approximately one hour, after which it can be brought out of service. The gas lighter will continue firing for another hour. After removal of the gas lighter from service, a five minute purge of the system will be required before the fans can be shutdown. The burner can be removed after shutting down the fans to permit hardware changes. If the unit is being shutdown for a longer period of time, the gas lighter should stay on for an additional hour and then brought out of service. The fans will continue to run at a low rate for some time.

IV. SO_x/PARTICULATE/AIR TOXICS/SOLID BYPRODUCT SUBSYSTEM

The scope of the SO_x/particulate/air toxics subsystem comprises the control of SO_x, particulate matter, hazardous air pollutant (commonly called "air toxics"), and solid byproduct from the B&W LEBS plant. The DOE program and B&W project design goals of the SO_x/particulate subsystem can be referenced to on pages 1 and 2.

The initial phase of this multi-phase project required a thorough review and assessment of potential advanced technologies and techniques for control of power plant emissions. For the control of SO_x and particulate emissions, numerous near-term advanced flue gas cleanup options were assessed and evaluated. A separate, but related, technology evaluation was performed for the selection of a particulate matter removal process for the B&W LEBS plant. On the basis of these results and other qualitative considerations, the B&W LIDS Process was selected for further development and evaluation in B&W's LEBS project.

The B&W LIDS process -- Figure 3 -- is a limestone-based furnace injection/dry scrubbing SO_2 removal process. The process actually comprises the cost-effective integration of three commercially-proven flue gas cleanup technologies: furnace limestone injection, dry scrubbing, and pulse-jet fabric filtration. Sulfur dioxide removal occurs in the furnace, dry scrubber, and in the fabric filter. Limestone is pulverized and injected as a dry powder into the flue gases in the upper furnace cavity of the boiler. Upon injection the limestone ($CaCO_3$) undergoes calcination to form lime (CaO), a portion of which reacts with SO_2 in the flue gases forming calcium sulfate ($CaSO_4$). The flue gases exiting the boiler then pass through a dry scrubber reactor where they are contacted by a slurry containing calcium hydroxide ($Ca(OH)_2$). In the dry scrubber the flue gases are cooled and humidified to conditions near the water saturation temperature -- commonly referred to as operation at a "low approach to saturation temperature". Under these conditions a portion of the SO_2 in the gases reacts with the $Ca(OH)_2$ in the slurry to form $CaSO_3$ and some additional $CaSO_4$. Water contained in the slurry droplets evaporates as the droplets pass through the reactor vessel, and leave the dry scrubber as a dry powder still suspended in the flue gases.

Finally, the flue gases enter the pulse-jet fabric filter (baghouse) where coal fly ash, spent sorbent, and reacted sorbent particles are collected. The use of a baghouse is a key feature of the LIDS process because of the additional SO_2 removal it yields as the flue gases pass through the sorbent containing filter cake on the filter bags. The majority of the solids from the particulate collection device are recycled to a reagent preparation (slaker) system to produce calcium hydroxide slurry for the dry scrubber. The remainder of the solids collected are conveyed to disposal and/or utilized.

A. Specific Objectives

<u>LIDS sulfur oxides control</u>

Sulfur Dioxide. Achieving the B&W LEBS project SO_2 removal goal of 0.10 lb SO_2/MBtu requires optimal SO_2 removal performance from the fully-integrated LIDS system -- this includes the furnace limestone injection, dry scrubbing, and pulse-jet fabric filtration processes. The ultimate ability to offer commercial guarantees on SO_2 removal for the LEBS power plant at the targeted levels is dependent upon the development of reliable performance data.

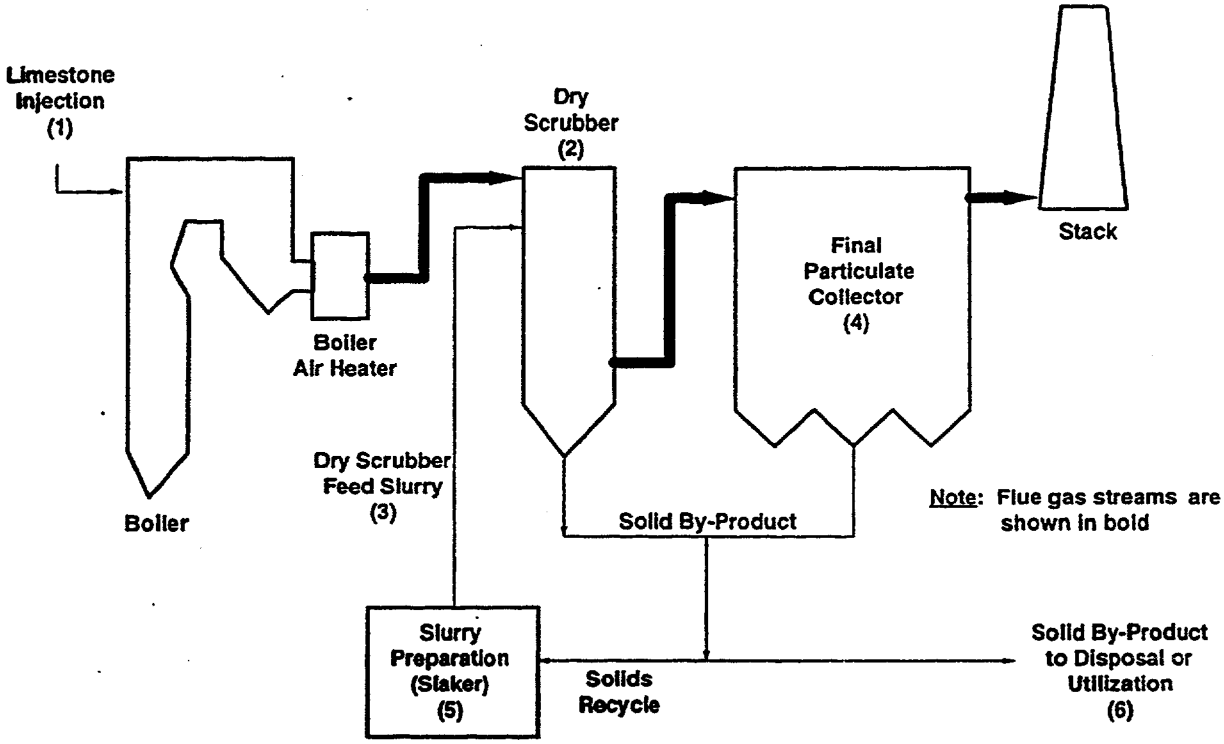


Figure 3 -- Limestone Injection Dry Scrubbing

Calcination of the limestone injected in the furnace limestone injection process must occur under ideal conditions -- injection temperature, time-temperature history, etc. -- in order to yield a highly reactive sorbent for optimum SO_2 capture (sulfation) in the furnace, and for optimal performance of the downstream dry scrubbing and baghouse SO_2 removal processes.

Dry SO_2 scrubbing is a key process in the LIDS system. The furnace limestone injection process facilitates the cost-effective use of a dry scrubber for SO_2 removal by: 1)permitting the use of limestone as the sorbent (as opposed to the more expensive lime sorbents used in most dry scrubbing processes), and 2) by reducing the inlet SO_2 concentration to the dry scrubber through in-furnace removal of the SO_2. In the dry scrubber, the SO_2 removal efficiency is maximized by increasing the amount of sorbent in the slurry and by operation near the flue gas saturation temperature.

The baghouse represents the final SO_2 removal stage for the LIDS system. Therefore, baghouse performance is critical to the overall SO_2 removal in LIDS. Key factors for the baghouse performance include the approach to saturation temperature, calcium stoichiometry, sorbent characteristics, and baghouse differential pressure (thickness of the filter cake). All of these things are examples of the process integration that must be proven for optimized SO_2 capture.

Two small pilot-scale (5 MBtu/hr) LIDS test series have been carried out in the B&W LEBS project to date. In Phase I, the feasibility of achieving the target SO_2 removal with the fully-integrated LIDS system was proven. Early in Phase II, the LIDS system configuration was further defined in the process definition test series. In Task 11, subsystem testing will be carried out to develop reliable performance data for the LIDS system at 100 MBtu/hr.

Sulfur Trioxide (SO_3). Along with improving the emissions capture of today's power plant, LIDS has the potential for improving the thermal efficiency of the power plant. One way this may be accomplished is through the removal of SO_3. There is evidence that sorbent injection of a calcium-based sorbent into the furnace/convection pass of the furnace removes a large portion of the SO_3 from the flue gases. Due to the removal of the SO_3, there exists a potential to reduce the air heater flue gas exit temperature below current standards due to the elimination of acid condensation concerns. According to IEA Coal Research, "Sorbent injection reduced the SO_3 concentration almost down to zero. This expected to reduce problems of cold end corrosion and make it possible to extract more heat from the flue gases and thereby improve the overall efficiency of the power plant."

The LIDS process is therefore able to take advantage of the furnace limestone injection process in improving the overall efficiency of the B&W LEBS. This is accomplished by reducing the air heater exit temperature because of the elimination of sulfuric acid condensation concerns -- therefore, reducing the overall power plant thermal efficiency. The LIDS SO_3 removal must be confirmed during subsystem testing.

<u>LIDS particulate matter control</u>

Achieving the B&W LEBS project particulate removal goal of 0.005 lb particulates/MBtu requires optimal particulate removal performance from the LIDS system. An integral part of the LIDS system is a pulse-jet fabric filter (PJFF). PJFFs have been applied to industrial boilers in this country, and on large utility boilers in Canada, Australia, and Europe. The flue gas in a PJFF passes from the outside of the bags to the inside and exits a tubesheet typically located in the top of the compartment. Ash is collected on the outside of the bags. The filter bags are cleaned by directing pulses of compressed air into each filter bag. The ash then falls into the compartment hoppers.

The chief advantage of pulse-jet technologies is that due to the more energetic cleaning method, they can operate at higher air-to-cloth ratios and thus use less total square footage of cloth. This can offer reduced space requirements and capital cost savings.

Although most of the information on attaining the LEBS particulate removal target will come from working with vendors and the literature, some observations of the LIDS pulse-jet fabric filter can be made during the subsystem test series.

<u>LIDS system operability and design</u>

The operability and design of the LIDS system must be quantified. Design standards and methods are needed for commercialization of the B&W LEBS concept. Such tools are also critical for the evaluation and development of design approaches. Subsystem testing in the CEDF will provide the first opportunity to address things such as the vertical dry scrubber configuration and deposition, furnace sorbent injection dispersion and mixing, the slurry slaking process, baghouse fabrics, and load following.

Optimal SO_2 removal in the boiler depends on adequate dispersion and mixing of the injected sorbent with the furnace gases. A standardized design methodology for achieving this must be demonstrated.

As boiler load changes, the boiler temperature distribution changes and the ideal temperature window for furnace limestone injection will move. It is extremely important to achieve effective calcination of the limestone in the furnace for SO_2 removal through the LIDS system. Therefore, it is important to learn at what point the injection locations used for full-load will be ineffective to determine how many levels of injection will be necessary for the LIDS system.

The LEBS dry scrubber will incorporate a vertical, down-flow reactor vessel. The down-flow configuration is proposed for two reasons. A vertical configuration minimizes the system "footprint," and also facilitates the use of a single hopper at the bottom. Horizontal dry scrubbers require several hoppers which make it difficult to handle deposits that tend to form in the hoppers. The use of a horizontal dry scrubber is not desired due to its large foot-print and complex solids handling. During subsystem testing the vertically oriented dry scrubber must be shown effective.

The LEBS dry scrubber will be a first-of-a-kind unit, especially when operation near the water dew point is taken into account. Deposition and dropout are major issues under these conditions. Incomplete droplet evaporation and the buildup of large deposits can cause severe operational problems for dry scrubbers. The amount of deposition and ways of dealing with the deposition, if it poses a problem, must be established. During subsystem testing the opportunity will be taken to verify the dry scrubber design methodology taken in terms of deposition.

The source of slurry for the dry scrubbing process is the LIDS slaking system. In order for the slurry to be optimum for SO_2 removal in the dry scrubber, an efficient slaker must be used. The performance impacts of various types of slaking systems -- detention slaking, continuous paste slaking, ball mill slaking, etc. -- are not fully understood for the LIDS process. The performance of the slaking system used during the subsystem tests must be observed and incorporated with information provided by the slaking system engineering analysis.

The low temperature and high particulate loading downstream of the dry scrubber reactor may present unknown filtration problems in the pulse-jet fabric filter baghouse. Problems may include fabric blinding, excessive bleed through, high pressure drop, and premature fabric failure due to high pulse frequency. The fabric selected in the Phase I fabric selection engineering analysis must be subjected to LIDS operating conditions.

<u>LIDS Air toxics control</u>

The performance of the LIDS process with respect to the capture of air toxics species must be further characterized. Air toxics capture is likely to be an important issue by the time the LEBS plant is commercialized. Title III of the Clean Air Act Amendments of 1990 (CAAA's) established a list of 189 hazardous air pollutants (commonly called "air toxics") and charged the U. S. Environmental Protection Agency (EPA) with the responsibility for regulating emissions of these substances into the atmosphere as required to protect public health and the environment. For most industries, plants emitting more than 10 tons/year of any one substance, or more than 25 tons/year of any combination of the 189 substances, will be required to apply the "maximum achievable control technology" (MACT). Electric utility plants are currently exempt from this requirement, however, pending the outcome of several risk assessment and emission characterization studies. The EPA is scheduled to propose its plan for regulating electric utilities under Title III in a report to Congress in November, 1995.

Since CAAA Title III was established, researchers have studied the trace emissions of heavy metals (including mercury), acid gases, and organics from power plants; their transport and fate in the environment; and health impacts. The results of major field testing programs are being reviewed by the EPA in conjunction with the results of several on-going EPA risk assessment studies to determine the need for air toxics emissions regulations aimed at coal-fired utilities. While the EPA's final approach is uncertain, it seems likely that at least some air toxics species issuing from utility stacks will be regulated.

B&W is already being requested to offer commercial guarantees on air toxics emissions in its boiler and environmental systems bids, even though such emissions are not yet regulated. For all of these reasons B&W believes that it is essential to consider the control of air toxics emissions. The final commercial LEBS plant developed during this program must be able to meet all air toxics regulations in place at that time -- not only federal regulations, but also local regulations which tend to be more stringent.

Mercury. Mercury, in particular, is the subject of intensive research due to its known buildup in the atmosphere, subsequent deposition in lakes, and potential human health impacts. It seems likely that mercury emissions will be regulated in some manner in the future. Researchers have shown that mercury can be removed in flue gas desulfurization systems under certain conditions. B&W's Phase I and II 5 MBtu/hr LIDS testing has shown that achieving 90%+ mercury capture is possible.

Trace Metals. Particulate regulations, although particulate itself is not an air toxic *per se*, are likely to become more stringent. A reason for this is that many of the trace elements of interest condense onto the particulate as the flue gas cools through backend emissions control equipment. Therefore, particulate removal systems have the potential to remove large amounts of air toxic substances associated with the particulate matter. A pulse-jet fabric filter operating at low temperatures is an integral part of the B&W LIDS system. This gives two possible advantages in terms of air toxics removal: 1) fabric filtration has been shown to be extremely effective in removing particulate and therefore many trace metals, and 2) the LIDS dry scrubber and baghouse are operating at low temperatures creating a higher potential for trace metals to condense out of the flue gas. The predicted successful trace metal removal of the LIDS system must be confirmed.

Acid Gases (HCl and HF). Acid gases have come under scrutiny primarily because of the large quantity of these substances emitted from electric power utilities. If acid gas regulations are required, coal-fired plants equipped with wet or dry FGD have been shown to achieve over 90% removal of HCl. Another form of HCl and HF control may be furnace sorbent injection. The LIDS acid gas capture efficiency must be investigated.

<u>Solid by-product minimization and/or utilization</u>
Coal-fired utilities currently generate a large amount of solid by-products due to standards adopted to control the emission of SO_2 from electric power stations. In the past, solid byproduct generation has been a low priority issue. However, recently it has become evident that it is important to assess the characteristics of the byproducts produced by coal-fired utilities in terms of their readiness for disposal as well as utilization prospects.

Utilization is an attractive economic and environmental alternative for management of the byproducts frequently generated by energy production. Clean coal technology by-products, such as the LIDS byproduct, exhibit significantly different characteristics from conventional coal byproducts, which generally include fly ash, bottom ash, and boiler slag. These conventional materials have been utilized as engineering and construction materials in numerous applications, and uses continue to be researched and developed.

Based on high potential utilization applications, LIDS laboratory-scale and field-scale characterization, and demonstration projects for similar clean coal technology residues, utilization applications were identified in the Phase I LIDS solid byproduct utilization engineering analysis. The utilization applications identified for further scientific and engineering investigation were:

- Abatement of acid mine drainage and mine reclamation

- Structural fill and other fills, including controlled low-strength material
- Soil amendment (road base, subbase, and agriculture)

Screening of potential utilization applications will be completed to evaluate performance and general interest in the utilization of LIDS materials.

B. Facility Modifications Needed to Meet Objectives

System Description

In order to accomplish the goals of the SO_2 subsystem Task 11 test series the CEDF will be modified to include a LIDS configuration. As discussed in the existing CEDF description above, a furnace, dry scrubber and pulse-jet fabric filter are all part of the existing base facility. Therefore, the three major units needed for the LIDS system are provided by the base CEDF and will be used as part of the LIDS configuration.

To complete the LIDS system a furnace limestone injection system, recycle solids system, ash slaking system, and an upstream particulate collection device will be added to the base CEDF. A description of each system is provided below.

Furnace limestone injection system. Pulverized limestone will be received from self-loading bulk transport trucks. The trucks will pneumatically fill a storage silo using a loading station located at grade level on the silo. The feed rate of limestone to the furnace will be controlled using a loss-in-weight feeder. The storage silo will discharge limestone into the 4.4 ft^3 weigh feeder hopper. A vibrating or aerated bin bottom will be used to promote flow from the silo. Limestone feedrate to the weigh feeder hopper will be controlled by a knife-gate valve. The hopper is mounted on a load cell which monitors the feed rate of the solids. Limestone is removed from the hopper at a controlled rate using a screw feeder. The speed of the screw is adjusted to match the change in weight of the hopper with the desired feed rate set point. When the level in the hopper reaches a pre-set value, the knife-gate is opened to allow more solids to flow into the weigh feeder hopper. The screw discharges the limestone into a rotary feeder which drops the solids into a pick-up box in the transport line.

A rotary blower will supply low pressure air for pneumatic transport of the limestone from the storage silo to the furnace injection ports. The blower is sized to transport the solids approximately 400 feet to the furnace injection ports while maintaining a minimum line velocity. A single line is used to transport solids to a splitter located near the injection ports. The limestone will be injected through the furnace wall into a temperature zone of 2100-2300 °F. Four port holes will be constructed, with two acting as spares. In this temperature zone, the limestone will calcine and then be carried over through the convection pass where lower temperatures are experienced. Sorbent dead-burning should not occur in this temperature range.

CEDF boiler high velocity thermocouple (HVT) measurements were taken during previous CEDF internal testing. The temperatures were used with numerical modeling to determine the injection port locations. After performing several runs, it was determined that the ports will be located on opposite sides of the furnace. The limestone will be injected into the furnace area with the same velocity through each port. From the numerical modeling, the limestone will be injected approximately half the width of the unit from each side in order to obtain optimal mixing of the sorbent.

The sorbent injection ports will be located in the upper portion of the furnace. The ports will be stationary. The port holes will be designed large enough to change the injection diameter pipe if needed during testing. Based on numerical modeling results, it was determined to split the flow at the end of the injection nozzle by a basic flow diverter. An option to remove the flow diverter during testing will be available. The nozzle will project into the unit approximately 2" beyond the refractory depth. Sight ports will be located on the opposite wall of the injection ports in order to confirm limestone flow through the injection ports.

The splitter for the limestone injection system will be located as close as possible to the injection port locations and centered between them. There will be a single line from the limestone feeder to the splitter. The splitter will allow for flow diversion to the spare ports, if necessary, resulting in injection through 4 ports. The piping from the splitter will be flexible metallic piping to permit easy application and contain internal wear resistant materials for the limestone system.

Recycle solids system. A portion of the solids collected in the baghouse will be recycled back to the ball mill slaker. On the base CEDF facility, flyash from the baghouse is transported to a disposal bin by a vacuum transport system. This vacuum transport system will be used to deliver a portion of the fly ash collected in the baghouse to the LIDS system. When solids are required for the LIDS system, a valve to the disposal bin will be closed and the valve to the LIDS system will be opened. The solids will be pneumatically transported to the LIDS system and collected in a small cyclone. This cyclone will discharge into a recycle solids surge bin with approximately five hours retention time. Solids from the bin will be metered into a ball mill slaker by a belt weighing feeder with a variable speed drive.

Ash slaking system. Solids collected in the particulate collector will be fed into a reagent surge bin through a rotary valve on the bottom of the particulate collector. The retention time in the bin will be approximately five hours. Solids from the bin will be metered into a ball mill slaker by a belt weighing feeder. The feeder will have a variable speed drive so that the proportions of reagent solids and recycled solids can be varied. The slaker will be a 3 ft. diameter by 3 ft. long conical ball mill. A grit screen on the ball mill discharge will remove any oversized material from the product. The product will be pumped to the reagent storage tank. From there, it will be pumped to the existing dry scrubber atomizing system. Make-up water for the slaker and dilution water for the dry scrubber injection system will be supplied by the existing CEDF dilution water tank and pump. The existing CEDF lime storage and slaking system will be used as an emergency back-up. If the CEDF LIDS system should fail, lime slurry could be pumped to the dry scrubber to keep the CEDF in compliance with B&W CEDF permits.

Particulate collection device. A cyclone dust collector will be added to the CEDF facility to collect a portion of the ash leaving the convection pass before reaching the dry scrubber. The approximate dimensions of the single cyclone are 8 ft. in diameter and 35 ft. high. Its estimated collection efficiency is between 75% and 85% depending on boiler load and the grind size of the limestone injected in the furnace. A bypass will also be added across the cyclone to control the ash collection efficiency. The solids collected will be sent to the ash slaking system

Instrumentation. The following instrumentation will be added to the existing CEDF facility (refer to the existing facility description for existing instrumentation):

Limestone injection system -- A standard low level indicator may be used to regulate sorbent levels in the storage silo to determine the need for limestone delivery. A weigh belt or loss-in-weight (LIW) feeder will be used to regulate the sorbent flow rate. Values for flow rate will be used to control the amount of fresh sorbent introduced to the system. The target set point will be determined from measurements of coal sulfur and overall SO_2 removal.

Cyclone dust collector -- A pressure gauge will monitor the pressure drop across the cyclone for indications of ash buildup. Thermocouples will measure the inlet and outlet gas temperature for indications of air infiltration, heat loss, and system performance.

Slurry preparation system -- Thermocouples will be used to monitor the temperature of water used in the ball mill slaker. Slaking temperature is an important variable in controlling the quality of the slurry product. Standard water flow meters will be used to measure flow rate to the ball mill which will be integrated with slurry density measurements to maintain consistent slurry densities. A flow meter will be used to measure the flow and density of the slurry stream from the ball mill. Slurry density can be related to solids concentration and used to control the consistency of the slurry product from the ball mill. Slurry flow to the scrubber will be controlled based on the scrubber outlet gas temperature. Thermocouples will monitor slurry temperature at the discharge of the ball mills as an indication of slaking efficiency. A weigh belt or LIW feeder will be used to regulate the baghouse and dust collector ash flow rate to the ball mill slaker. The target set point will be based on the designed throughput of the ball mill and desired slurry density.

Dry scrubber and baghouse -- In addition to the existing dry scrubber and baghouse instrumentation the following will be added. Gas analyzers will be used to measure the SO_2 and O_2 concentrations in the flue gas at the inlet and exit of the dry scrubber and baghouse. These values will be used to calculate furnace, dry scrubber, and baghouse performance and to regulate the limestone feed rate to the furnace and slurry flow rate to the dry scrubber.

Equipment List

The SO_2/Particulate subsystem LIDS facility major equipment list is in Table 1.

Material balance

The SO_2/Particulate subsystem LIDS material balance is in Appendix B.

General Arrangement Drawing

The SO_2/Particulate subsystem LIDS general arrangement drawing is in Appendix B.

Adequacy of the test facility to meet the stated objectives

The CEDF is an excellent test bed for the SO_2/particulate/air toxics/solid byproduct subsystem tests. It is designed for a heat input of 100 MBtu/hr, and integrates combustion and post-combustion testing capabilites to facilitate the development of the next generation of power generation equipment. The burners and combustion furnace accurately simulate full-scale utility pulverized coal combustion practice. They have been carefully designed to yield combustion zone temperatures, flow patterns, and residence times representative of commercial boilers. For the purposes of the SO_2 subsystem, this is extremely important for work on air toxics removal. It is imperative that the mix of air toxics species leaving the combustion furnace is representative of commercial units.

Boiler convection pass and air heater simulators maintain representative conditions through the entire boiler system to facilitate studies of air toxics capture in the LIDS dry scrubber and baghouse. Representative gas phase time-temperature profiles and surface metal temperatures are maintained throughout the convection pass. Convection pass metal temperatures are maintained in the 600-1100°F range by way of a novel double-wall tube design.

The facility is already equipped with a dry scrubber and baghouse, two of the major components needed for the LIDS system. The existing dry scrubber is a vertical downflow device, representative of the LEBS dry scrubber design concept, and has been proven in operation. The pulse-jet baghouse, also consistent with B&W's LEBS plant concept, is a six-module baghouse containing commercial-size filter bags.

The third major component needed for the LIDS system is a furnace injection system. This process has been demonstrated at full-scale by B&W and others. B&W has subsequently installed commercial furnace limestone injection systems on demonstration units and full-scale utility boilers. Confidence can therefore be taken in that the furnace limestone injection system modification to the CEDF will be successful in attaining the LIDS testing goals.

Other systems added to the CEDF to complete the LIDS system include a slaking system and ash recycle system. These are standards offered with B&W's commercial dry scrubbing systems.

Table 1 Major Equipment List - SO_2/Particulate Subsystem

SYSTEM	EQUIPMENT
Limestone Storage & Feed System	Limestone Storage Silo
	Limestone Feeder
	Limestone Transport Air Blower
	Limestone Injection Line Splitter
	Limestone Injectors (4)
Particulate Collection and Storage System	Cyclone Particulate Collector
	Cyclone Particulate Collector Solids Surge Bin
	Cyclone Particulate Collector Solids Feeder
Dry Scrubber System (Existing CEDF System)	Dry Scrubber
	Slurry Atomizer
	Slurry Feed Pump
	Atomizing Air Compressor
Solids Slaking System	Ball Mill Slaker
	Reagent Slurry Storage Tank
	Slurry Transfer Pump
	Dilution Water Tank
	Dilution Water Pump
	Existing CEDF Lime Silo & Slaker (Back-up System)
Baghouse and Recycle Solids System	Pulse Jet Baghouse
	Pulse Jet Air Compressor
	Vacuum Ash System for Waste Solids
	Vacuum Ash System Additions for Recycle Solids
	Recycle Solids Cyclone Collector
	Recycle Solids Storage Bin
	Recycle Solids Feeder

C. Test Plan

The LIDS testing to be performed under Task 11 of Phase II will primarily concern the optimization, operability, and sensitivity of the LIDS process. The tests will also provide an opportunity for characterization of air toxics emissions and LIDS solid byproduct utilization methods.

Tests to be performed

Sulfur Oxides Removal. SO_2 capture testing will be performed to quantify the influence of key LIDS process independent variables on the overall performance and operability of the LIDS system. Parametric testing to obtain LIDS SO_2 removal performance curves will be the aim of the subsystem test program. Based on the results of parametric testing, the optimum LIDS operating conditions can be determined and be taken with confidence to the POC testing in Phase 4.

Key independent variables that may be investigated include: 1) furnace injection -- furnace injection temperature (firing rate), limestone type, limestone grind, fresh Ca/S stoichiometry at the furnace, 2) dry scrubbing -- operating temperature (approach to saturation, T_{as}), resulting Ca/S stoichiometry in the dry scrubber, slurry solids content, atomization quality, and reactor residence time, 3) baghouse -- operating temperature (T_{as}), Ca/S stoichiometry in the baghouse, and bag cleaning method.

EPA Method 8 will be used to make SO_3 removal measurements. The measurements will be made at the outlet of the convection pass to prove that virtually all of the SO_3 has been removed prior to entering the flue gas cooler (air heater). Measurements will be made with and without limestone injection. In the EPA Method 8 an isokinetically-drawn sample of flue gas is bubbled through isopropanol and hydrogen peroxide solutions in series. Subsequent chemical determinations result in quantities of H_2SO_4 present in the impinger solution. The measured quantity of H_2SO_4 is converted to its equivalent quantity of SO_3. Knowledge of the quantity of flue gas sampled allows the investigator to determine the SO_3 concentrations in terms of parts per million.

Particulate Matter Removal. Although most of the information on attaining the LEBS particulate removal target will come from working with vendors and the literature, some observations of the LIDS pulse-jet fabric filter can be made during the subsystem test series. Particulate emissions can be obtained during subsystem testing as part of EPA Method 29. As described later in this section, EPA Method 29 will be used for obtaining mercury and trace metal emission data and particulate emissions can be determined in addition to the metals emissions if the prescribed procedures and precautions are followed.

The pulse-jet fabric filter on the CEDF was not specifically designed to obtain the particulate matter emissions target of 0.005 lb particulate/MBtu. However, observations can be made and incorporated with information from vendors and the literature allowing for a LIDS pulse-jet fabric filter design that can attain the LEBS targeted particulate emissions goal.

Operability and Design. Subsystem testing in the CEDF presents the first look at operability and design of the LIDS system. Throughout the SO_2 removal parametric studies discussed above, observations will be made on the operability of the LIDS system on the CEDF. The information obtained can be used in future LIDS system designs.

Observations to be made during SO_2 subsystem testing may include the following: limestone injection dispersion and mixing, vertical dry scrubber operation and deposition potential, slaking system performance and its impact on the dry scrubber slurry, and baghouse fabric performance. As opportunities present themselves, short tests to address operability and design may be carried out.

An example of a operability test would be to decrease the CEDF firing rate and therefore decrease the temperature in which the limestone sorbent is injected into. This would determine at what temperature the full-load injection ports are deemed ineffective for successful calcination of the sorbent. This information would then be used with modeling predictions to locate the low-load sorbent injection ports for the POC demonstration in Phase IV. The LIDS Phase II subsystem testing will be performed using the CEDF single burner configuration without overfire air addition. Modeling will be used to confirm that the furnace temperatures in the CEDF in the Phase IV POC multiple burner configuration with overfire air will be similar to those encountered for sorbent injection in Phase II.

Air Toxics. Screening tests of mercury, trace metals/fine particulate, and acid gas emissions across the LIDS system will be completed during subsystem testing. Based on the results of these Phase II air toxics measurement results and the *Report to Congress on Air Toxics and the Electric Power Utility* due in November, 1995, the Proof-of-Concept air toxics program will be developed.

Mercury measurements will be carried out using 2 methods -- Frontier Geosciences, Inc., and EPA Draft Method 29. The Frontier Geosciences, Inc., method is a mercury speciation adsorption (MESA) method which uses solid sorbent collection and cold vapor atomic fluorescence spectroscopy detection (CVAFS). The MESA method sampling system for gas phase mercury speciation in flue gas employs a series of heated solid phase adsorbent traps. Oxidized mercury, both Hg(II) and mono-methyl mercury (MMHg), are adsorbed by the KCl/soda lime granules, while Hg^0 passes through and is adsorbed onto the iodated carbon. The KCl/soda lime traps are manufactured in the laboratory. The iodated carbon traps are commercially available, and designed for the collection of mercury vapors. Trace element clean techniques are applied throughout sampling and analysis to minimize sources of contamination.

EPA Draft Method 29 is a method applicable to the determination of mercury as well as many other metal emissions from stationary sources. This method may be used to determine particulate emissions in addition to the metals emissions if the prescribed procedures and precautions are followed. A stack sample is withdrawn isokinetically from the source, particulate emissions are collected in the probe and on a heated filter, and gaseous emissions are then collected in an aqueous acidic solution of hydrogen peroxide (analyzed for all metals including Hg) and an aqueous acidic solution of potassium permanganate (analyzed only for Hg). The recovered samples are digested, and appropriate fractions are analyzed for Hg by cold vapor atomic absorption spectroscopy (CVAAS).

EPA Draft Method 29 will also be used to determine trace metal emissions from the LIDS system during subsystem testing. Based on the results of the *Report to Congress on Air Toxics and the Electric Power Utility* due in November, 1995, the specific trace metals to be measured will be selected. (Antimony, arsenic, barium, beryllium, cadmium, chromium, cobalt, copper, lead, manganese, nickel, phosphorus, selenium, silver, thallium, and zinc can be measured with the method.) For all metals the recovered samples are digested, and appropriate fractions are analyzed by inductively coupled argon plasma emission spectroscopy (ICAP) or atomic absorption spectroscopy (AAS).

For acid gas (HCl and HF) measurements, EPA Method 26a will be used. The method is applicable for determining emissions of hydrogen halides (HX) and halogens (X_2) from stationary sources. This method collects the emission sample isokinetically and is therefore particularly suited for sampling at sources that emit acid particulate matter.

Solid Byproduct. A screening of possible LIDS solid byproduct uses will be carried out during subsystem testing. Possible uses identified in Phase I included:

- abatement of acid mine drainage and mine reclamation,
- structural fill and other fills, including controlled low-strength material, and
- soil amendment (road base, subbase, and agriculture).

These uses were identified through a B&W/OCDO utilization development project entitled "Management of Solid Wastes from the Limestone Injection Dry Scrubbing (LIDS) Clean Coal Technology," and an engineering analysis carried out in LEBS Phase I by the Energy and Environmental Research Center at the University of North Dakota. The work performed in the B&W/OCDO LIDS utilization project will be built upon during the Phase II LEBS utilization testing.

LIDS solid byproduct produced during the Phase II subsystem tests will be used for screening projects to evaluate performance of the LIDS byproduct in utilization applications. The solid byproduct will be used in selected utilization methods. Based on the results of the screenings a utilization strategy will be selected for demonstration during Phase IV Proof-of-Concept operation.

<u>Data Acquisition</u>

The personal computer based, STARS/LabVIEW Data Acquisition System will be used for acquiring data during the SO_2 subsystem test series. The system is a suite of five applications which allow the user to perform generic data acquisition operations, as shown in Figure 4. The application participates in each step of data flow involved in data acquisition.

The following key variables (at a minimum) will be continuously monitored: limestone feed rate (Ca/S), total flue gas flow, O_2 and SO_2 concentrations, dry scrubber operating temperature, baghouse operating temperature, slurry flow rate, and system pressure drops. Other variables will be monitored remotely.

<u>Data analysis and reduction</u>

All results from tests performed will be critically evaluated. A comparison of the results of each test with the test plan objectives will be carried out to assess the extent to which the research needs were met. Where a deficiency in test data exists it will be clearly identified. Where a deficiency in subsystem performance exists this will also be clearly identified. At the completion of the LIDS system testing it will determine if the subsystem requires further development or if it is ready for scale-up and inclusion in the POC test facility.

Test data obtained from the facility through the data acquisition system and/or tabulated raw test data will be reduced and compared. The LIDS system will be evaluated in terms of: SO_2 removal, particulate removal, air toxics removal, solid by-product utilization strategies, and system operating conditions and performance.

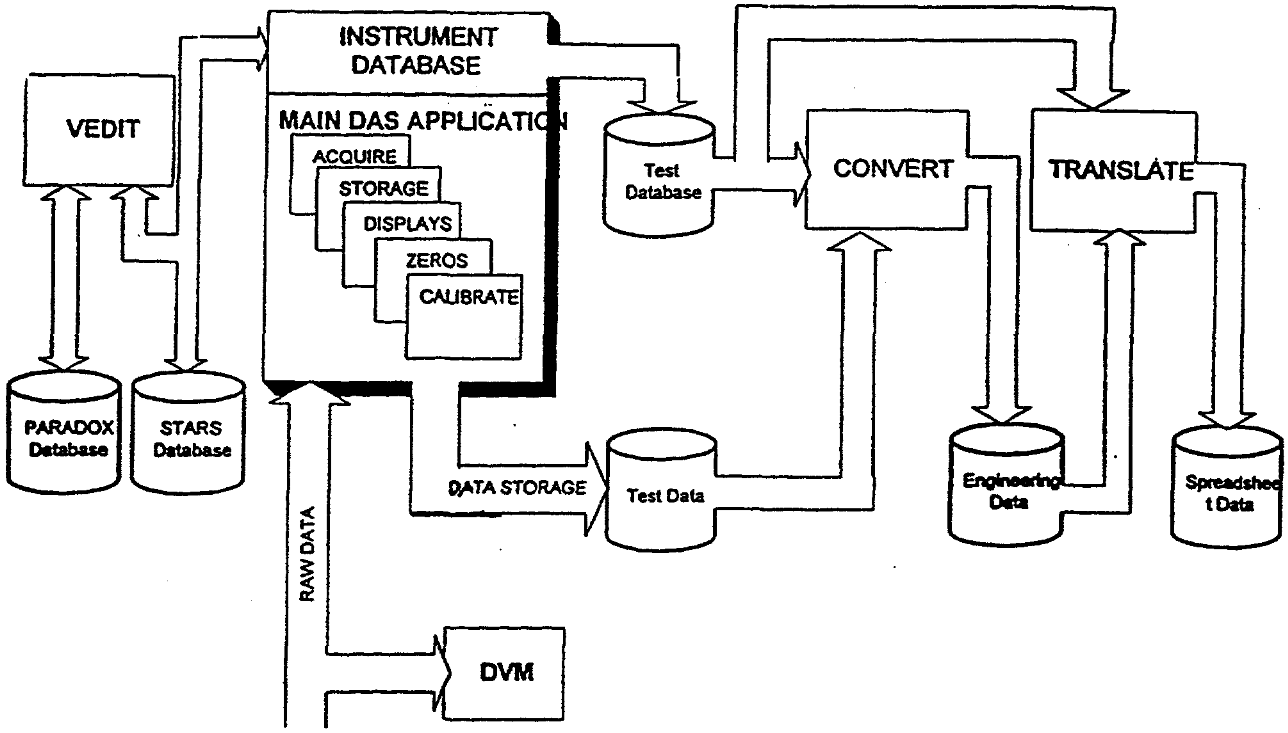


Figure 4 -- STARS/LabVIEW Data Acquisition System Diagram

<u>Start-up and shutdown procedures</u>
Standard start-up and shutdown procedures will be followed for the base CEDF during SO_2 subsystem LIDS testing. Refer to the NO_x subsystem CEDF start-up and shutdown procedures on pages 19-20.

To start-up the LIDS system, lime slurry prepared in the base CEDF slurry preparation system will be used in the dry scrubber for SO_2 capture to be in compliance with existing B&W operating permits for SO_2 emission. After enough solids have been collected from the LIDS furnace limestone injection process, LIDS slurry will be made in the LIDS slurry preparation system. After enough LIDS slurry has been prepared the CEDF lime slurry system will be shut down and the slurry to the dry scrubber will be changed over to the LIDS slurry. At this point LIDS operation will be underway. An inventory of backup lime slurry will be kept in the CEDF slurry preparation system for emergencies.

Shutdown of the LIDS system will occur by stopping the limestone injection process and then running the LIDS slurry out of the system. Once all of the LIDS slurry is used up, the base CEDF slurry preparation system will be used to remain in compliance until complete shutdown is accomplished.

V. CONTROLS/SENSORS SUBSYSTEM

A. Specific Objectives

Unburned Carbon Monitoring

Operation of the main coal burners at substoichiometric levels may cause a prohibitive increase in the amount of unburned carbon (UBC) or gaseous combustibles exiting in the flue gas. Therefore, reliable measurements of unburned carbon and combustibles should be obtained for use as limiting factors (directional blocking) to prevent any further reduction of air/fuel ratio when UBC or CO exceed allowable maximum values.

There are several types of systems available for measuring UBC. Continuous unburned carbon analyzers can be used but none have been operated over a long enough time period to determine their accuracy and reliability. Also, there are UBC monitors that require elaborate sampling systems to extract ash particles from multiple locations in the gas flue. However, the time required to analyze samples and produce a feedback signal may be too long for on-line control. Another method would be to measure flyash reflectance from a filter, which would be quicker, but probably not as accurate. The system that shows the most promise is the patented Carryover Monitoring System (CMS) built by Diamond Power.

The CMS employs multiple sensors to quickly and accurately monitor on-line, luminous particle activity in a boiler. The CMS is one of proven reliability which, to date, has primarily been utilized on chemical recovery boilers to monitor carryover for reduction of gas-side pluggage problems.

A prototype Carryover Monitoring System (CMS) will be built, installed, and tested on the CEDF. The CMS is expected to provide spark count data (a count of glowing particles passing the sensors) which will be correlated with actual ash sampling data and ultimately provide an indication of the amount of UBC leaving the boiler.

Burner coal flow and primary air flow

The objective of this effort will be to verify the adequacy and accuracy of the sensors used to measure burner pulverized coal flow and primary air flow.

B. Facility Modifications Needed to meet objectives

Unburned Carbon Monitoring

Subsystem testing will occur at B&W's Alliance Research Center in the Clean Environment Development Facility (CEDF). The CMS system will utilize either two or four sensors mounted across or near the furnace arch. A specially designed cable will supply power to each sensor and return spark data signals to a common processor box. Each sensor and processor provides a linear 4-20 mA channel that is scaled from 0 to 100 sparks per second. The sensors will require filtered compressed air (60 to 100 psi) for lens purging and cooling.

The CMS system will consist of the following equipment:

1. A processor box containing processor cards that convert spark counts from the sensors to 4-20mA control loops.

2. A three stage air filter assembly.

3. Two sensors with mounting rails.

4. Belden 8162 cable from each sensor to the processor card.

5. A mounting plate for each sensor.

Burner coal flow and primary air flow
Two pulverized coal flow sensors and two primary air flow sensors will be installed in the single 12-inch ID burner line between the coal injection location and the burner on the CEDF. The pulverized coal sensors will be microwave meters by Endress+Hauser. The primary air flow sensors will be thermal mass flow meters by Kurz Instruments Inc.

C. Test Plan

Unburned Carbon Monitoring
Testing of the CMS system will be performed during testing of the LEBS advanced low-NO_x burner. The following CMS Test Plan is proposed:

1. Install two or four CMS Sensors on the CEDF boiler.

2. In addition to the continuous monitoring of CMS data, the following data will be continuously monitored and used for experimental control:

    a. NO_x
    b. Stack O_2
    c. Stack CO
    d. Furnace Exit Gas Temperature
    e. Stack Fly Ash Unburned Carbon
    f. Coal Flow
    g. Combustion Air

3. Compare CMS data to LOI ash sample data to establish a correlation between CMS spark count and measured stack fly ash unburned carbon.

The results of the CMS test are expected to be used to refine the control system design, to identify and solve accuracy and reliability problems and to demonstrate long-term unattended operation of the system.

Burner coal flow and primary air flow
The output of these meters will be connected to the DAS and compared to the coal flow and primary air flow obtained by the CEDF instrumentation. Both steady-state and transient data will be acquired. No special tests will be conducted. Sensor output will be recorded during NO_x subsystem testing at reduced-load and full-load conditions.

VI. GENERAL SUBSYSTEM TESTING ISSUES

A. Safety

The R&DD Safety and Health Procedures manual will be followed throughout subsystem testing. Emergency and accident reporting procedures, communications/preplanning, health environment, safety equipment/clothing, medical/first aid, fire protection, material handling, walking/working surfaces, machines, hand/portable tools, welding/cutting/brazing, electrical, offsite procedures, and audits/inspections/tests are subjects covered in the manual.

The McDermott Safety Philosophy is as follows:

"Safety -- the McDermott commitment"

- All accidents and injuries can be prevented.
- Management is responsible for providing a work environment that is safe to the employee.
- Supervisors are accountable for the actions of their subordinates.
- Employees are responsible for preventing injuries to themselves and their co-workers.
- Working safely is a condition of employment.
- No job or operation is so important that it cannot be done safely.
- Training is essential to a successful safety program.
- Prevention of accidents and injuries is good business.

B. Management procedures for monitoring and controlling all procurement and construction

The B&W management team will supervise, direct, plan, manage and analyze all the work tasks with the goal of accomplishing the technical objectives named in this report in a timely and cost-effective manner.

The team will perform the activities needed to effectively manage the project, employing those management and planning tools and techniques normally used for controlling technical performance, schedule and budget. This includes the establishment and maintenance for management systems in accordance with the B&W Contract Research Division (CRD) Policies and Procedure manual for monitoring and controlling schedules, costs, technical performance, manpower, procurements and quality of work. These management systems will use the orderly application of standard B&W management techniques and procedures, as appropriate. The techniques will be applied to this project management system based on proper training, plan management and plan variance control.

C. Quality Assurance/Quality Control (QA/QC)

The work described in this report will be carried under the B&W Research & Development Division's (R&DD) Standard Practice. Standard Practices are those activities normally performed by the B&W R&DD when no specific requirements are imposed. Standard Practice is the baseline operating level designation for normal business practices of the Division. These practices are described in the Standard Practice Manual and are further implemented by R&DD Administrative Procedures. When no specific conditions are customer-imposed upon the research project, Standard Practices are automatically applied, without additional cost to the customer.

Quality Assurance exercises general surveillance over projects conducted according to Standard Practice. Periodically, projects are selected randomly for audit for compliance with applicable R&DD Administrative Procedures and to criteria identified as good engineering practices.

Project records are available for customer review at the Research and Development Division. The retention of these records is in accordance with B&W policy (minimum one year) or as specified by customer requirements, applicable codes, standards, or specifications.

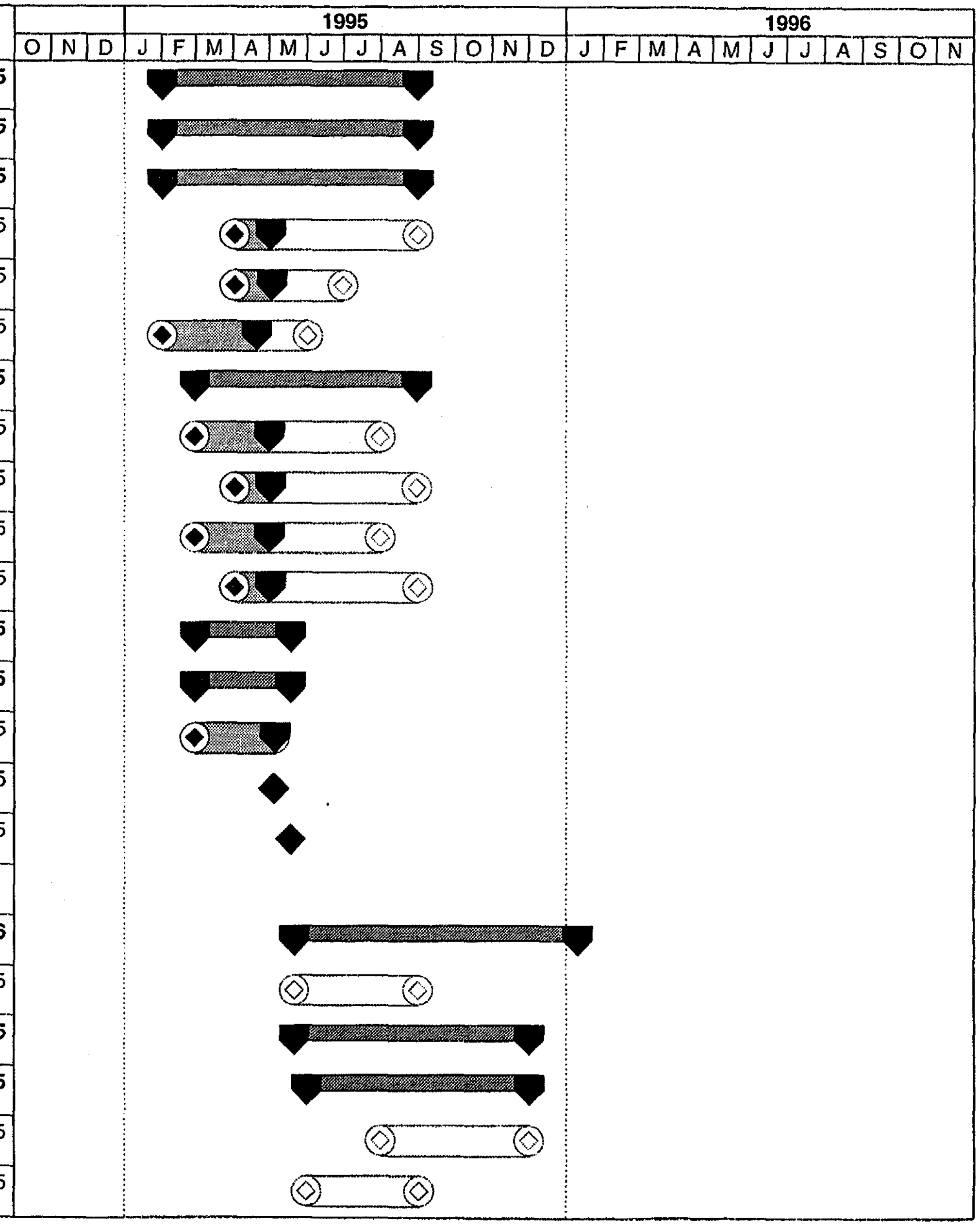
B&W has previously submitted the QA/QC Plan which DOE has approved. The contractor's QA/QC Plan addresses all tasks of the subsystem test plan in accordance with the latest issue of DOE Order 5700.6B entitled, "Quality Assurance."

D. B&W LEBS Task 9 - 11 Subsystem Test Design, Construction, and Testing Schedule

The B&W LEBS Task 9-11 Schedule can be found on the following three pages.

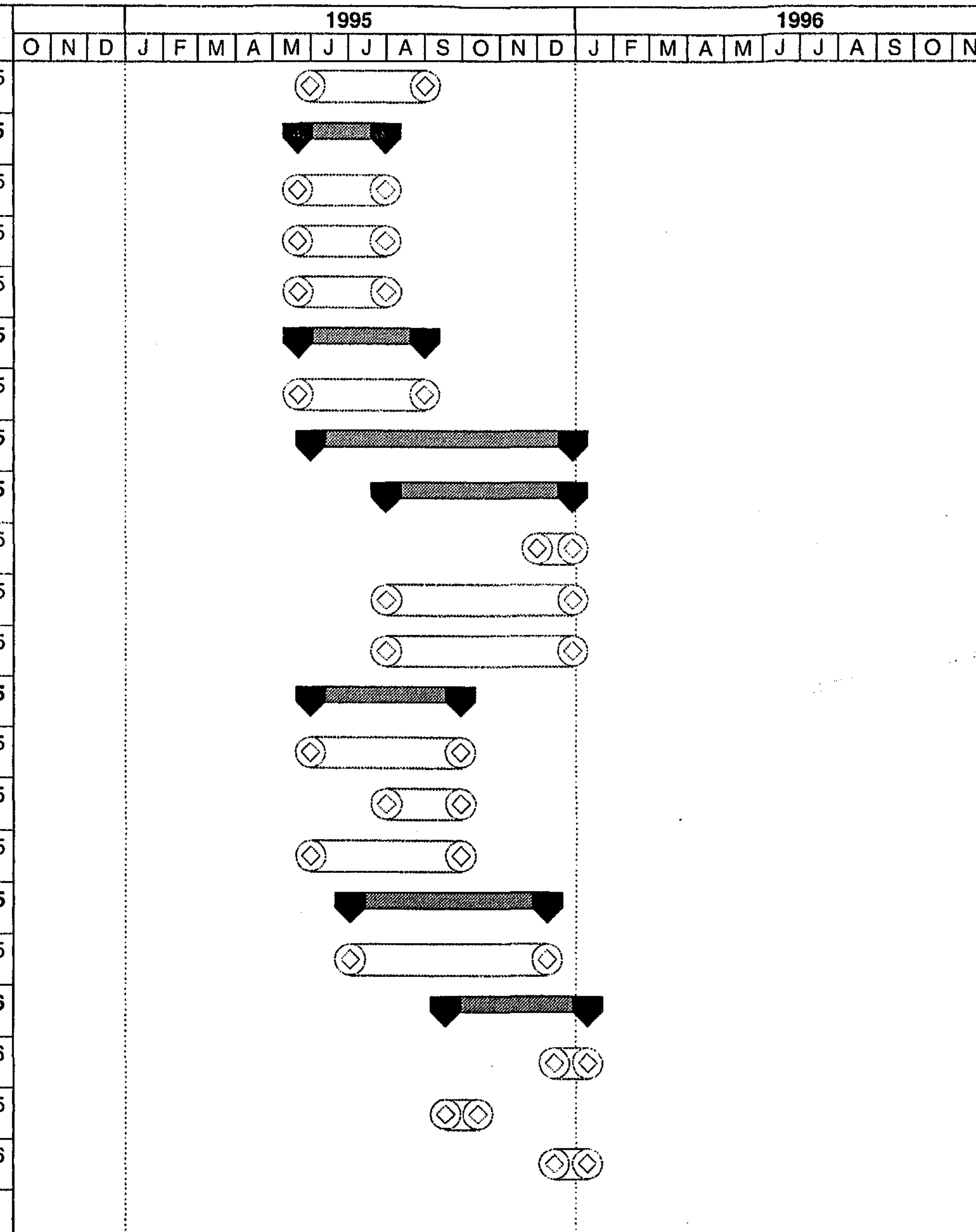
Babcock & Wilcox LEBS Tasks 9-11
Project Schedule

ID	Task Name	Start	Finish
1	***9.0 Subsystem Test Design and Plan***	**Thu 2/2/95**	**Thu 8/31/95**
2	**9.1 Subsystem Test Unit Design**	**Thu 2/2/95**	**Thu 8/31/95**
3	**9.1.1 NOx Subsystem**	**Thu 2/2/95**	**Thu 8/31/95**
4	9.1.1.1 Burner System Design	Mon 4/3/95	Thu 8/31/95
5	9.1.1.2 OFA System	Mon 4/3/95	Fri 6/30/95
6	9.1.1.3 Corrosion Test System	Thu 2/2/95	Thu 6/1/95
7	**9.1.2 SOx Subsystem**	**Wed 3/1/95**	**Wed 8/30/95**
8	9.1.2.1 Limestone Preparation/Injection System	Wed 3/1/95	Mon 7/31/95
9	9.1.2.2 LIDS Instrumentation	Mon 4/3/95	Wed 8/30/95
10	9.1.2.3 Ash Handling/Particle Separator/Slaking System	Wed 3/1/95	Mon 7/31/95
11	9.1.3 Controls and Sensors Subsystem	Mon 4/3/95	Thu 8/31/95
12	**9.2 Test Plan**	**Wed 3/1/95**	**Fri 5/19/95**
13	**9.2.1 Updated RD&T Plan**	**Wed 3/1/95**	**Fri 5/19/95**
14	9.2.1.1 Detailed Subsystem Plans	Wed 3/1/95	Fri 5/5/95
15	9.2.1.2 Submittal of Plan to DOE	Fri 5/5/95	Fri 5/5/95
16	9.2.1.3 Approval by DOE	Fri 5/19/95	Fri 5/19/95
17			
18	***10.0 Subsystem Test Unit Construction***	**Mon 5/22/95**	**Wed 1/10/96**
19	10.1 Permitting (ARC 410)	Mon 5/22/95	Thu 8/31/95
20	**10.2 Procurement and Fabrication ARC 410, 335)**	**Mon 5/22/95**	**Fri 12/1/95**
21	**10.2.1 NOx Subsystem**	**Thu 6/1/95**	**Fri 12/1/95**
22	10.2.1.1 Single Burner System	Tue 8/1/95	Fri 12/1/95
23	10.2.1.2 Overfire Air System	Thu 6/1/95	Fri 9/1/95



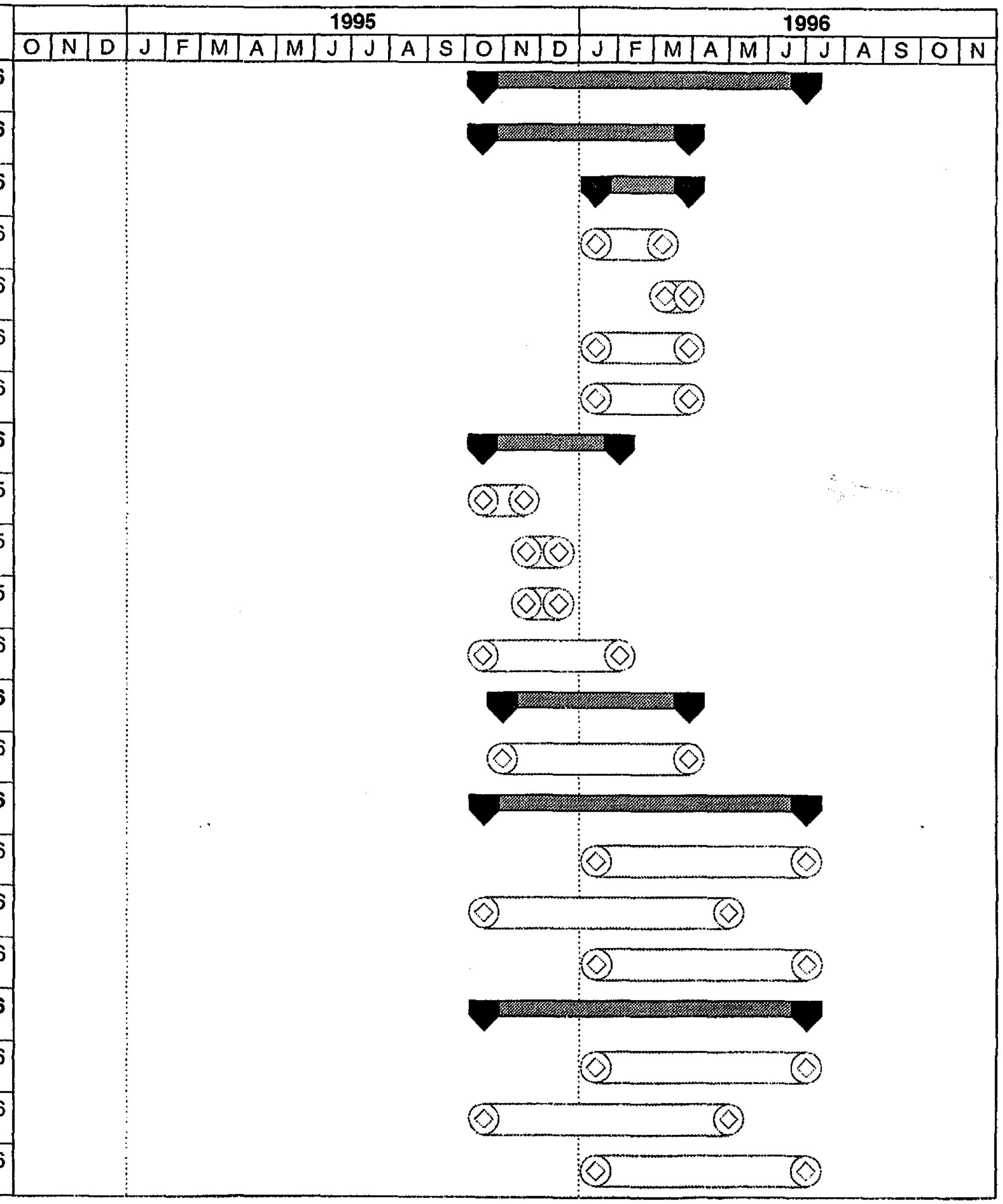
Babcock & Wilcox LEBS Tasks 9-11
Project Schedule

ID	Task Name	Start	Finish
24	10.2.1.3 Corrosion Study System	Thu 6/1/95	Fri 9/1/95
25	**10.2.2 SOx Subsystem**	**Mon 5/22/95**	**Mon 7/31/95**
26	10.2.2.1 Limestone Preparation/Injection System	Mon 5/22/95	Mon 7/31/95
27	10.2.2.2 LIDS Instrumentation	Mon 5/22/95	Mon 7/31/95
28	10.2.2.3 Ash Handling/Particle Separator/Slaking System	Mon 5/22/95	Mon 7/31/95
29	**10.2.3 Controls and Sensors Subsystem**	**Mon 5/22/95**	**Thu 8/31/95**
30	10.2.3.1 Coal Sensor	Mon 5/22/95	Thu 8/31/95
31	**10.3 Construction**	**Thu 6/1/95**	**Fri 12/29/95**
32	**10.3.1 NOx Subsystem**	**Tue 8/1/95**	**Fri 12/29/95**
33	10.3.1.1 Single Burner System	Fri 12/1/95	Fri 12/29/95
34	10.3.1.2 Overfire Air System	Tue 8/1/95	Fri 12/29/95
35	10.3.1.3 Corrosion Study System	Tue 8/1/95	Fri 12/29/95
36	**10.3.2 SOx Subsystem**	**Thu 6/1/95**	**Fri 9/29/95**
37	10.3.2.1 Limestone Preparation/Injection System	Thu 6/1/95	Fri 9/29/95
38	10.3.2.2 LIDS Instrumentation	Tue 8/1/95	Fri 9/29/95
39	10.3.2.3 Ash Handling/Particle Separator/Slaking System	Thu 6/1/95	Fri 9/29/95
40	**10.3.3 Control and Sensors Subsystem**	**Mon 7/3/95**	**Fri 12/8/95**
41	10.3.3.1 Coal Sensor	Mon 7/3/95	Fri 12/8/95
42	**10.4 Start-up and "Shakedown"**	**Mon 9/18/95**	**Wed 1/10/96**
43	10.4.1 NOx Subsystem	Fri 12/15/95	Wed 1/10/96
44	10.4.2 SOx Subsystem	Mon 9/18/95	Fri 10/13/95
45	10.4.3 Controls and Sensors Subsystem	Fri 12/15/95	Wed 1/10/96
46			



Babcock & Wilcox LEBS Tasks 9-11
Project Schedule

ID	Task Name	Start	Finish
47	***11.0 Subsystem Test Operation & Evaluation***	**##########**	**Mon 7/1/96**
48	**11.1 System Test Operations**	**##########**	**Fri 3/29/96**
49	**11.1.1 NOx Subsystem**	**Mon 1/15/96**	**Fri 3/29/96**
50	11.1.1.1 Adv. Burner Performance Testing	Mon 1/15/96	Fri 3/8/96
51	*11.1.1.2 OFA Stability Evaluation*	*Mon 3/11/96*	*Fri 3/29/96*
52	11.1.1.3 Corrosion Study Testing	Mon 1/15/96	Fri 3/29/96
53	11.1.1.4 Fuel Preparation Testing	Mon 1/15/96	Fri 3/29/96
54	**11.1.2 SOx Subsystem**	**##########**	**Fri 2/2/96**
55	11.1.2.1 LIDS Optimization Tests	##########	Fri 11/17/95
56	11.1.2.2 LIDS Operability Test	##########	Fri 12/15/95
57	11.1.2.3 Air Toxics Capture Testing	##########	Fri 12/15/95
58	11.1.2.4 Solid By-Product Utilization Testing	##########	Fri 2/2/96
59	**11.1.3 Controls and Sensors Subsystem**	**Wed 11/1/95**	**Fri 3/29/96**
60	*11.1.3.1 Coal Sensor*	*Wed 11/1/95*	*Fri 3/29/96*
61	**11.2 Subsystem Test Evaluation**	**##########**	**Mon 7/1/96**
62	11.2.1 NOx Subsystem Team Evaluation	Mon 1/15/96	Mon 7/1/96
63	*11.2.2 SOx Subsystem Team Evaluation*	##########	Tue 4/30/96
64	11.2.3 Controls and Sensors Subsystem Team Evaluation	Mon 1/15/96	Mon 7/1/96
65	**11.3 Subsystem Design Evaluation**	**##########**	**Mon 7/1/96**
66	11.3.1 NOx Subsystem Team Evaluation	Mon 1/15/96	Mon 7/1/96
67	11.3.2 SOx Subsystem Team Evaluation	##########	Tue 4/30/96
68	11.3.3 Controls and Sensors Subsystem Team Evaluation	Mon 1/15/96	Mon 7/1/96



Appendix A

NO_x Subsystem

Test Material Balance,
General Arrangement Drawing,
and
Process and Instrument Diagram

```
Basis:    8232 lb/hr of Illinois No 6     Fuel at        3.85 % moisture AS FIRED
                Fuel had      3.9 % moisture and        12148 Btu/lb as received.

       MKB/hr =   100.00
  COAL------------------------------------------------------------------------------>+
            Dry =  7914.9                                                 % by wt    |
            H2O =   316.9       3.9 %                         Carbon       67.32     |
                 ---------                                    Hydrogen      4.96     |
                   8231.8     12148 Btu/lb                    Sulfur        4.32     |
                              (as fired)                      Nitrogen      1.19     |
                                                              Chlorine      0.00     |
                                                              Oxygen        9.24     |
Pulverizer     p =      0.0 "H2O          +---------------+   Ash           9.12     |
 PRI. AIR--------------------------->| Pul PA Fan    |   Moisture      3.85     |
            Dry = 14137.6       100 °F+------+--------+                ------     |
            H2O =   185.8                   t =  |   100 °F                  100.00     |
                 ---------                  p =  |       "H2O                         |
                  14323.3 lb/hr                  |                                    |
                 (    3395 ACFM )                |                                    |
                                                 V                                    |
                                          +------+--------+                           |
 Nat. GAS--------------------------->| Air Heater    |                           |
            CH4 =     23.0                +------+--------+                           |
                 (     8.6 ACFM )           t =  |   247 °F                            |
                 (    0.52 MBtu/hr)              |                t  =        60 °F    V
                                                 |   +-----------------------------------+
                                                 |   |
                                                 V   V
                                          +------+--------+
                                          | Pulverizer    |
                                          +------+--------+
                                            t =  |   125 °F
                                            p =  |       "H2O
                                                 |   A/F =     1.740   #/# wet coal
                                                 V
                                          +------+--------+ Vent Air, t=     125 F
                                          | Surge Bin     |------------------------->
                                          +------+--------+ Dry Air    =  14137.6
                                                 |         (CH4 Comp)  =     23.0
                                                 |          H2O (V)    =    362.6
                                                 |                         ---------
                                                 |                         14523.2
                                                 |
                                                 V         PULVERIZED COAL
                                                 + ----------------------------------->+
                                                             Dry      =   7914.9       |
                                                             H2O (L)  =    140.1   1.7 % |
 BURNER        p =     -7.4 "H2O          +---------------+                ---------    |
 PRI. AIR--------------------------->|   PA Fan      |                 8055.0      |
% of TA =   Dry = 14625.1       100 °F+------+--------+                             |
   16.7     H2O =   192.2                   t =  |   118 °F                            |
                 ---------                  p =  |  28.6 "H2O                          |
                  14817.3 lb/hr                  |                                    |
```

```
                                            V
                                        +------+--------+ Motive Air =     0.0 lb/hr      |
                                        | Air Spliter   |->-+-------------------------->+   |
                                        +------+--------+   | @ 6 psi=         0 SCFM   |   |
                 Main PA = 14817.3  lb/hr      |            |                            |   |
                             100.0  % of PA    |            |Seal Air      0.0 lb/hr     |   |
                                               |            +------------------->+       |   |
Comb. Air-------------------------------+      |                   0 ACFM        |       |   |
T.Air,%=     Dry =  2222.1         80   |      |                                 |       |   |
  200.0      H2O =    29.2              |      |                                 |       |   |
                   ---------            |      |                                 |       |   |
                    2251.3            +-+      V                                 |       |   |
                                      V +------+--------+ Flue gas,t =     696 °F|       |   |
 Nat. GAS-----------------------------+->| Air Heater    |------------------>     |       |   |
        Nat. gas=    45.7               +------+--------+         Dry     2172.6 |       |   |
               (     16.8 ACFM )          t =  |  232 °F          H2O      124.4 |       |   |
        (Q to air    0.41 MBtu/hr)        p =  | 21.8 "H2O             --------- |       |   |
        (H'r Eff=      40 %)                   |                          2297.0 |       |   |
                                               |                                 |       |   |
                                               V                                 |       |   |
                 t =      80            +------+ -------+                        |       |   |
   Water-------------------------------->| Evaporator    |                        |       |   |
             H2O =    176.8             +------+--------+                        |       |   |
                                          t =  |  184 °F                         |       |   |
                                          p =  | 20.8 "H2O                       |       |   |
                                               |                                 V       V   |
                                               |    +----------------------------+---+   |
                                               |    |                                    |
                                               V    V                                    |
                 t =      80            +------+--------+        t=        125 F         V
 N2 Purge------------------------------>| Bin Pickup    |<--------------------------------+
               N2 =      0.0            +------+--------+
                                          t =  |  150 °F
    Air to fuel =   1.800 #/#             p =  | 20.82 "H2O
        based on As Rec. coal                  |          Dry Coal =    7914.9
  with moisture =     3.85 %                   V          Dry Air  =   14625.1
                                               +--------------------------------->+
                                                          H2O (L)  =     140.1    |
                                                          H2O (V)  =     369.0    |
                                                                     ---------    |
                                                                       23049.1    |
                                                                                  |
                           t =      80  °F          Secondary Air to burner(s)    |
Comb. Air-------------------------------+          +-<-----------------------------(  |  )<----+
T.Air,%=     Dry = 14495.4              |          |                Dry =   72802.8  |        |
  200.0      H2O =   190.5              |          |                H2O =     956.6  |        |
                   ---------            |   t =    |  558 °F               --------- |        |
           Total = 14685.8              |   p =    | 11.0 "H2O              73759.4  |        |
               (     3356 ACFM        +-+          V                                 |        |
                                      V +------+--------+ Flue gas,t =     696 °F    |        |
 Nat. GAS-----------------------------+->| Trim Heater   |------------------>         |        |
        Nat. Gas=   298.2               +------+--------+         Dry    14172.7     |        |
               (    117.7 ACFM )          t =  |  700 °F          H2O      811.4     |        |
        (Q to air    2.69 MBtu/hr)        p =  |  4.6 "H2O              ---------    |        |
        (H'r Eff=      40 %)                   |                         14984.0     |        |
                                               |                                     |        |
                                               V          Excess Air                 |        |
OFA @ 25% of SA =    18440              +======+========+at burner  =        15 %    V        |
 True Sec. Air  =    55320              | BURNER        |---------------------------+        |
                                        +======+========+        t=        150 °F            |
                                          t =  | 3721 °F         p=        11.7 "H2O         |
```

NO_x Subsystem Test Material Balance

```
                                                p = |   0.0 H2O
                                                    V
                                          +-----+-------+       (Q =      25.9 MBtu/hr)    |
                                      +--->| FURNACE    |----------------------------->    |
Treated Water                         |   | . Boot      |       Steam=   25921.3           |
    H2O ----------------------->+     +-----+-------+                                      |
        98097.2                       |      t = | 2900 °F                                 |
      (   196.2 GPM)                  |          |                                         |
                                      |          V                                         |
         Dry gas = 90943.3            |   +-----+-------+ Bottom Ash Loss @        20 %    |
         H2O     =  5114.5            |   | HOPPER      |----------------------------->    |
         Dust    =   600.6            |   +-----+-------+ Bot. Ash =     150.1             |
                     -----            |          |                                         |
           total = 96658.4            |          V                                         |
            (SO2 =     3766 ppm)      |   +-----+-------+       (Q =      20.2 MBtu/hr)    |
            (HCl =        0 ppm)  +--->| FURNACE    |----------------------------->        |
             (O2 =     2.80 %)        |   | Shaft       |       Steam=     20167             |
            Hum. =0.056238 #/#        |   +-----+---+-----+                                |
         .............V.......        |          |   | Total Blowdown@       8.3 %         |
                      +--------{      | }--------o   +----------------------------->       |
                                      |          |             H2O(1) =      7518          |
                                      |     t =  | 2250 °F          (      15.0 GPM)       |
                                      |     p =  |  0.0 "H2O                               |
                                      |          |                                         |
                                      |          V                                         |
                                      |   +-----+-------+                                  |
    LIDS----------------------{       | }->| MIXER      |                                  |
         CaCO3  =        0.0          |   +-----+-------+                                  |
         Inerts =        0.0          |          |                                         |
         Air    =        0.0          |          |                                         |
          (Ca/S =       1.40          |          |                                         |
                                      |          V                                         |
                                      |   +-----+-------+       (Q =      44.5 MBtu/hr)    |
                                      +--->|CONVECTION  |----------------------------->    |
                                          +-----+-------+       Steam=   44490.8           |
                                          t =   |  680 °F                                  |
               Wet flue gas               p =   | -0.9 "H2O                                |
               Mol Wt =    29.75                |                                          |
                                                V                                          |
                p    13.6 "H2O            +-----+-------+       (Q =       8.0 MBtu/hr)    |
SEC. Air --+----------------------->|Sec Air HX  |-----+------------------------->+
% of TA =  | Dry = 72802.8       105      +-----+-------+  | t =        558 °F
    83.3   | H2O =   956.6               t =  |  369 °F    | p =       12.0 "H2O
           |     ---------               p =  | -2.7 "H2O  |
           |      73759.4                     |            | Sec vent air=    0.0 % of Sec
           |        17066 ACFM @ t & p)       |            +--------------------->  air
           |                                  |              Dry  =       0.0          to burner
           o-- Airheater leakage =            |              H2O  =       0.0
           |     ( for both)        1 %       |                       ---------
           |                                  |                           0.0
           |                         *        V
           |           0.1 "H2O           +-----+-------+       (Q =       0.5 MBtu/hr)
VENT AIR -+----------------------->|Gas Cooler  |----------------------------->
          || Dry =  7363.7      100  °F+-----+-------+          t=        368 °F
          || H2O =    96.8               t =  |  350 °F        p =        0.0 "H2O
          ||     ---------               p =  | -5.8 "H2O
          ||      7460.4 lb/hr    (t(dp) =    | 109.4 °F)
          ||                                  |          Dry gas    =   91744.9   Hum. =
          ++--------------------------------->|          H2O        =    5125.0 0.05586 #/#
           Dry =  801.66                      |          Dust       =     600.6   (SO2 =
           H2O =   10.53                      o---------                  -----
```

NO_x Subsystem Test Material Balance

```
                                                |           total gas =   96870.0
                                                V           Gas Composition:
              Scrubber takes      0.0 % +------+--------+          CO2      15.52 %, dvb
Net Gas            of Main gas flow     |Wet Scrubber   |          O2        2.97
Input    --------------------------->|Extraction &   |          Ar        0.95
         Net Dry =      0.0  Return     |Wet gas        |          N2       80.18
         Net H2O =      0.0  Gas t =    |Return Sys.    |          SO2       0.37   {ppm =    373
                  ---------       100 °F+------+--------+          HCl       0.00   {ppm =
                        0.0       p =          |                    CO        0.00   {ppm =
                                    0  "H2O    |                   NOx       0.00   {ppm =
          (Return gas Flow =        0  lb/hr)  |
          (                         0  ACFM)   |
          (includes Ox air =        0  lb/hr)  |
                                       t =  |  350  °F
                                  (t(dp) =  | 109.4 °F)
VENT AIR ----------------------------------+   |
              Dry =  2223.8      100 °F  |    o---------Dry gas    =   91744.9
              H2O =    29.1              |    |          H2O        =    5125.0
                   ---------             |    |                          -----
                     2252.9 lb/hr        |    |          total gas =   96870.0
              2.34 % of flue gas to DSR  |    |
                                         V    V              to DSR        % dvb
CaO             t =        80  F            +------+--------+          O2        2.97
Slurry   --------------------------->|Dry Scrub      |          SO2       0.37   {ppm =    373
          Ca(OH)2 =  1890.1     30.6 % +------+--------+          HCl       0.00   {ppm =
          Inerts  =   158.9     solids         |
       slaker H2O =  4652.6                    |
          Atom air=  1474.4                    |
          H2O in A=     4.1               t =  |  146  °F   (T(sat)=      131.0 )
       dilut. H2O =     0.0               p =  |  -9.0  "H2O
                  ---------                    V
                     8180.0                +------+--------+  Fly Ash =      600.6
          (Ca/S =      2.30 )              |BAG HOUSE      |-----------------------------→
                                           +------+--------+CaSO3.*H2C=    1095.8    *= 1/2
                  ^                        t =  |  146  °F  Ca(OH)2 =      1191.6
                   (Rho =      30.58 %)        |              Inerts  =      158.9
                   (recyc=       0.0 )         |            CaSO4.2H2C=      162.3
                  +-----------------           |                CaCl2  =        0.0
                  Internal ash recycle         |              H2O(l)  =       33.6    1.04 %
                                          P =  | -19.8  "H2O                ---------
                                               V                            3242.8
                                           +------+--------+Mol Wt; wet gas
                                           |  DAMPER       |   29.00
                                           +------+--------+
                                          P =  | -26.8  "H2O
                                               |
                  CEDF elevation =             |ACFM    =      28450
                              1100 feet        V
                                           +------+--------+Flue Gas
                                           |  ID FAN       |-----------------------------→
                                           +---------------+  Dry gas =    94824.0    Hum. =
                                              t=      161 °F  H2O     =     9836.7  0.1037 #/#
                                              p=      3.2 "H2O                -----
                                                                   total =  104660.7
     PROCESS :  Comb. 2K JLS Conditions Task 8                        SO2=       1.07 lb/MBtu
FLOWSHEET DATE :     21-Apr 1995                                        =        537 ppm

   FUEL BURNED : Illinois No 6                PROCESS FEATURES:     (Yes = 1, No = 0)
     Excess Air =          15 %                  LI (?)       =        0
  PA/Coal @ Burn =      1.800 #/#                DS only (?) =        1
                                                 WS slip str ?        0
```

NO_x Subsystem Test Material Balance

Design Conditions; Pulverizer, Furnace, Convection Bank:

Excess Air =	15 %	Equivalance Ratio=	0.87	
Pulv Pri Air/Fuel=	1.74 #wet air/# as-received coal			
Pulv Exit Temp =	125 °F (Coal temp in PC bin)			
Burner A/F ratio =	1.8 #wet air/# as-received coal			
Motive Air =	0 #wet air/# as-received coal			
Seal Air =	0 #wet air/# as-received coal			
Pulv'd Coal Bulk D	30 lb/ft^3;	Coal Part Sp Gr =	1.20	
Nitrogen Inerting=	0 (Yes = 1, No = 0)			
Burner line temp =	150 °F	FD Fan in temp =	100	F
Air Preheat (Sec)=	700 °F	Bottom ash loss =	20	%
Furnace Exit temp=	2250 °F	Vented Sec Air =	0.20	#/#Sec air
Conv Bank Exit T =	680 °F			
Blowdown rate =	8.3 %	Air Heater leakage =	1	%

Design Conditions; LIDS, Dry Scrubber, & Wet Scrubber (Slip Str):

Sulfur Capture =	30 %; In furnace only, W/Lids			
Ca/S ratio; Fur. =	1.4 LIDS in furnace			
LIDS air ratio =	4 #/# limestone			
Limestone Quality=	90 % (Balabce is SiO2)			
Ash Recycle Ratio=	0 % (If LIDS is used)			
Wet Scrubber div.=	0 % of main flow (If used)			
Wet Sc Exit temp =	100 °F, Sat.; Gas returnen to Main stream			
Wet Sc exit Press=	0 "H2O	Gas returns to Main stream		
Oxidation air =	0 #/# dry gas; returns to main gas			
Dry Scrb in Temp =	350 °F (If <300°F Vent Secondary Air)			
Sulfur Cap. in DS=	85 % in DS and Baghouse			
Ca/S ratio in DS =	2.3 Mol/mol	Lime Quality =	90	%
Approach to Sat. =	15 °F	Air/Slurry in DS=	0.22	#/#

Combustion Efficiency:

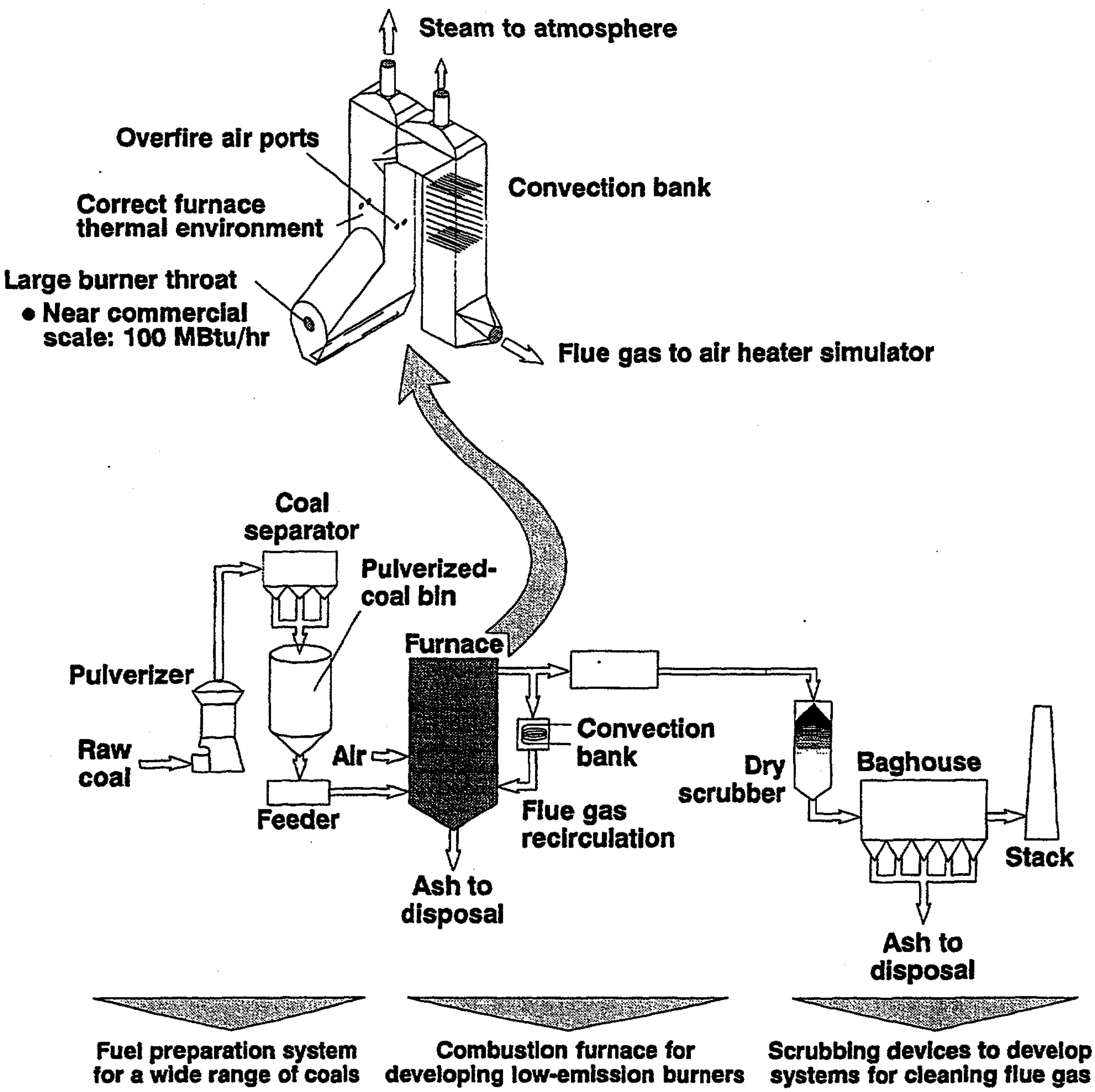
Heat released =	100 % based on unburned Carbon c	14500	Btu/# C
CO =	0 % of carbon input		
NOx formation =	0 % of fuel nitrogen		

MATERIAL BALANCE:

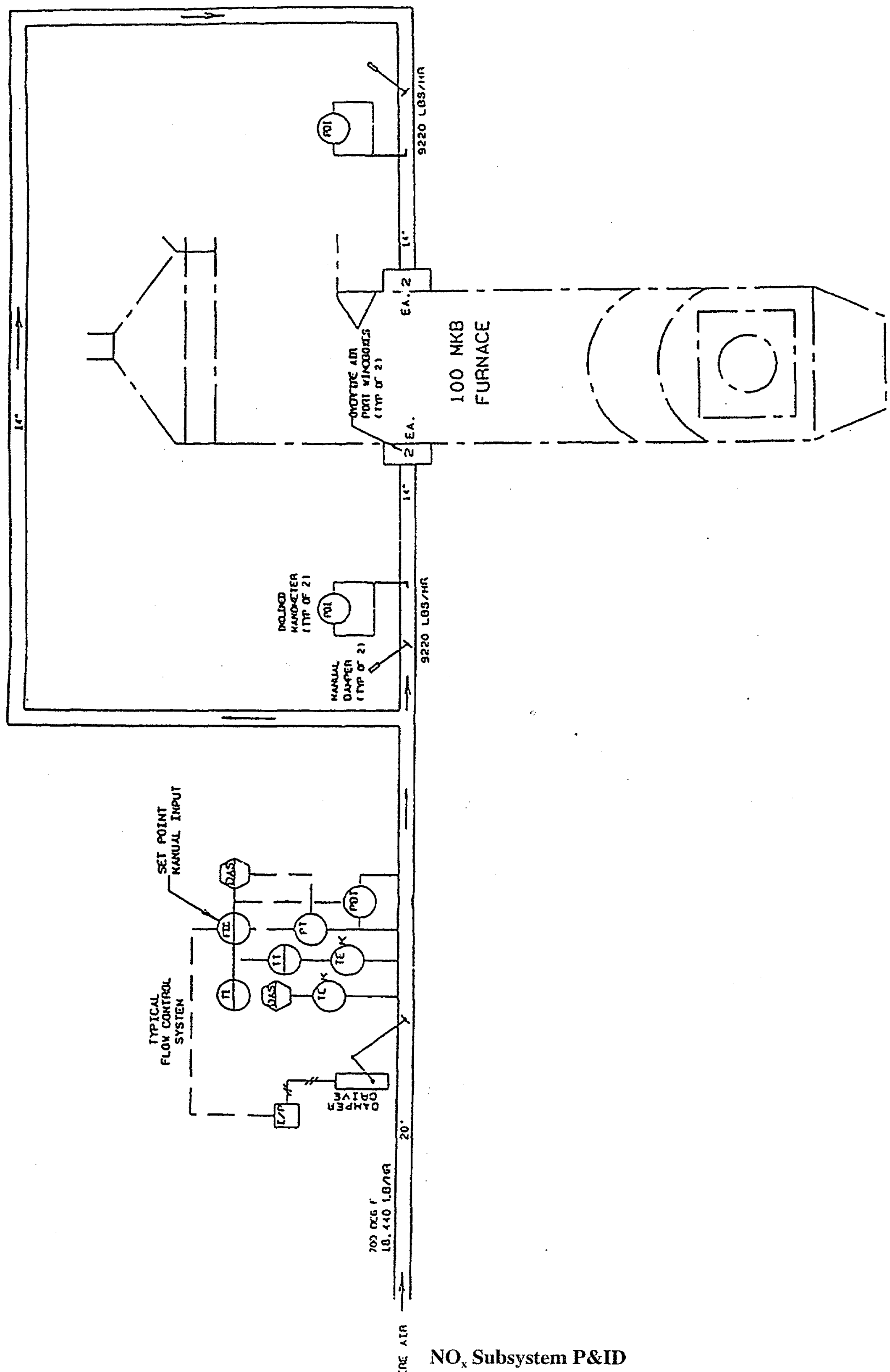
IN		OUT	
Coal	8232	Pulv Vent gas	14523
N2 Purge	0	Dry Flue Gas	94824
Pulv. Air	14323	H2O in flue gas	9837
Gas PAHtr	23	Slag + Fly Ash	751
PRI.AIR	14817	Hyd.Calcium salts	2642
Steam	177	Vented Secondary Air	0
SEC AIR	73759		
LIDS	0		
LIDS air	0		
Dry Scrub	8180		
Vent air	2253		---------
AH leak	812		122577
H2O @ WS	0		
	---------	Error (in - out) =	0
TOTAL	122577	% of input	0.00

Gas Fired Air heater Material Balance

IN		OUT	
NG to PA	46	Flue gas; PA heater	2297
Air to PA	2251	Flue gas; Trim heater	14984
NG - Trim	298		
Air; Trim	14686		
	---------		---------
	17281		17281



NO_x Subsystem General Arrangement Drawing



NO_x Subsystem P&ID

Appendix B

SO_2 Subsystem

Test Material Balance
and
General Arrangement Drawing

NOTICE